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TN PUBLIC UTILITY COMMISSION
DOCKET OFFICE

jjeffries@mcguirewoods.com

September 10, 2020

VIA FEDEX

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Petition for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in Tennessee; Docket No.: 20-00086

Dear Mr. Taylor:

Enclosed for filing are Piedmont Natural Gas Company's ("Piedmont") responses to the Consumer Advocate's *First (Informal) Discovery Request* in the above-referenced docket. Native files can be found at the following link: https://mcguirewoods.sharefile.com/d-s0e6e4afd2b547d4b.

Some of the materials provided are confidential and proprietary trade secrets of Piedmont. Therefore, Piedmont respectfully requests that the Tennessee Public Utility Commission treat those materials in a manner consistent with that designation.

Thank you for your assistance with this matter. If you have any questions about this filing, you may reach me at the number shown above.

Sincerely,

/s/ James H. Jeffries IV
James H. Jeffries IV

JHJ/sko

Enclosure

cc: Paul Davidson
David Foster
Michelle Mairs
Vance Broemel
Daniel Whitaker
Karen Stachowski

Bruce Barkley
Pia Powers
Melinda McGrath

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-1. Refer to the Company's response to MFR #10 and provide the following information.

a. Provide a chart of accounts for all accounts listed in the trial balance. If the Company does not have an available chart of accounts (as indicated in the response to MFR 5) then fully explain the reason for this. Further explain how the Commission can obtain a specific description for each of the accounts used by Piedmont to record the transactions in its ledger.

b. Confirm whether the data included in this trial balance is for Tennessee only. If not, then provide a Tennessee only trial balance from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

c. Provide a specific explanation of the differences between the "Reg Values" and "SEC Values" trial balance schedules.

RESPONSE:

a. See DR 1-1 attachment 1 for a comprehensive list of all accounts used by Piedmont. Piedmont follows the uniform system of accounts prescribed by FERC. FERC account descriptions are provided here: link

b. The data provided by the Company for its response to MFR item 10 was not specific to TN. See DR 1-1 attachments 2 through 20 for TN allocated income statements and total company balance sheets for May 2011 through March 2020. Please refer to MFR item 10 for 2018-March 2020 total company balance sheets. Piedmont does not have state specific balance sheets.

c. "Reg Values" represents the working trial balance for the Piedmont regulated utility. "SEC Values" represents the working trial balance for the Piedmont SEC

registrant that support the financial statements presented in the 10-K. The difference between the two is that the SEC registrant includes the Piedmont regulated utility in addition to activity for a legal entity that holds equity method investments (Pine Needle, Cardinal, Hardy Storage), and any accounting adjustments made specifically for the SEC reporting of our GAAP financial statements.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-2. Refer to the Company's response to MFR #10. Update this response to provide a detailed monthly trial balance from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 for Tennessee and DEBS.

RESPONSE: For Tennessee monthly trial balances, please refer to the Company's response to DR 1-1. Please refer to DR 1-2 attachment 1 for DEBS monthly trial balances from October 2016 through March 2020.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-3. Refer to the Company's response to MFR #10. Provide a monthly trial balance that includes the detailed subaccounts for gas plant in service and accumulated depreciation from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 for Tennessee and DEBS

RESPONSE: See the 20 attached reports which contain the monthly plant in service roll forward reports generated from Piedmont's asset accounting system of record, PowerPlan. Each monthly report contains the month end balance in plant in service by plant utility account from May 2011 - March 2020 for Piedmont TN.

Please see the Company's response to Request No. 37 of this data request for the accumulated depreciation roll forward reports for Piedmont TN.

Since Piedmont was acquired by Duke Energy in October of 2016, Piedmont has provided the monthly roll forward reports for DEBS affiliate from October 2016 - March 2020.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-4. Refer to the Company's response to MFR #52 regarding the LDC's budgeting process and provide the following information.

a. Provide a copy of the board-approved capital budget for 2020 in the same format as the Attachment to MFR #52.

b. Provide a comparison of the actual capital expenditures and board-presented capital budgets by year from 2011 (date of the last rate case) through 2017 in the same format as the Attachment to MFR #52.

c. Provide a copy of the board-approved operating budget for 2020 for Tennessee operations and all affiliates.

d. Provide a copy of the actual operating expenditures and board-presented operating budgets by year from 2011 (date of the last rate case) through 2019 for Tennessee operations and all affiliates.

RESPONSE: Please see the three attachments. Note that the information in the attachments is for Total Piedmont, since capital and operating budgets are approved and reviewed at this level of detail.

Name and Title of Preparer: John Robson, Director - Gas FPA

Name and Title of Responsible Person: Joel Rutledge, Director - Finance Gas Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-5. Refer to the testimony and exhibits of Company witness Watson regarding the proposed Depreciation Rate Study and provide the following information.

a. Provide a copy of the Depreciation Rate Study, including all workpapers, in Excel format with formulas intact.

b. Provide a copy of all communication between Dane Watson and Alliance Consulting Group with the Company and its affiliates regarding the current depreciation study.

c. Provide a side-by-side comparison of the depreciation rates proposed in this Docket with the studies conducted by Alliance for depreciation rates approved by the Commission in Docket No. 18-00017 for Chattanooga Gas Company and Docket Nos. 14-00146 & 15-00089 for Atmos Energy Corporation, explaining any material differences.

d. Provide a calculation of the $155,695 impact from the implementation of Vintage Group Amortization rates as noted in Footnote 13 of Exhibit DAW-2, Page 71.

RESPONSE:

a. See the four attachments.

b. Please see attachments. Piedmont is producing non-privileged communications between Dane Watson and Alliance Consulting Group with the Company and its affiliates regarding the current depreciation study. Piedmonts objects to producing any communications that constitute attorney-client privilege, work product, or are subject to any other applicable privilege.

c. Piedmont has not performed a comparative analysis and objects to performing such an analysis on the basis that the request is unreasonable, irrelevant, over-reaching and imposes an undue burden on the Company.

d. Please see Exhibit DAW-2 Page 74 of 89 (Depreciation Study Report, Appendix B, Page 2 of 2) as provided in response to part a of this question for the calculation of the Vintage Group Amortization and the requested calculation of the $155,695 annual impact to true up the depreciation reserve at implementation. The Appendix shows a comparison of each account's book to theoretical reserve. The calculated difference, surplus or deficiency, is proposed to be amortized over a five year period.

For Piedmont, there were both surpluses and deficiencies among the accounts. For the accounts where a surplus is calculated (291, 295 and 298), the amount will reduce expense over a period of five years. For the accounts where a deficiency is calculated, it will increase expense over a period of five years. The net effect of these individual account calculations is a reserve deficiency of $778,473.97, which is proposed to be amortized over five years, resulting in the $155,694.79 annual amortization.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

From: Rhonda Watts
To: Lepisto, Denise; Burnes, Wendy; Abernathy, Melissa Brammer
Cc: Dane Watson
Subject: RE: PNG TN Preliminary Rates
Date: Wednesday, April 29, 2020 3:23:25 PM

Hi Denise,

Do you have a way to get more detail on what the assets are in both accounts? The listing I have does not show detail on the assets. In one of the provided files, it noted 26620 as S&I for compressor station, which there is no compressors in transmission currently. So, based on that it might make sense to do a transfer from 26620 into 26900 for plant and reserve. It would eliminate the negative rate on the book reserve scenario and the existing rate is the same for both accounts. I am not sure how PP does its allocated reserve calculation but I do see there is a little variance.

We can include this as a discussion point on our call, but I like the idea of a transfer to 26900 if it makes sense based on the specific assets. Of course Dane's input/agreement is required..

Thanks,
Rhonda

From: Lepisto, Denise [mailto:Denise.Lepisto@duke-energy.com]
Sent: Wednesday, April 29, 2020 12:40 PM
To: Rhonda Watts; Burnes, Wendy; Abernathy, Melissa Brammer
Cc: Dane Watson
Subject: RE: PNG TN Preliminary Rates

Rhonda,

You had a note on the draft results regarding the 26900 assets – I double checked and those assets are using depr group 26620 and therefore a 2.14% rate. I remember there being a similar issue on the NC study. I'm not exactly sure what happened her, but I can see that additions started happening in 2013 and it looks like they just used decided for some reason to use the 26620 rate. It looks like the recommended rate doesn't change that much. That explains why the 26620 looks like it's overdepreciated – I ran a NBV for the 26620 and 26900 assets for 12/2019. It is attached. This is a little different than what is shown on the "Accrual w/ Alloc Res" tab in the draft results. My theory being if we process a transfer in PP to a new depr group (26900 Depr group) and give it the same rate as the 26620 group, I think we would see Powerplan break out the reserve similar? I'm not sure. Thoughts on what you think we should do here?

Denise

From: Abernathy, Melissa Brammer
Sent: Wednesday, June 24, 2020 12:31 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

See attached for final Testimony for Dane.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Wednesday, June 24, 2020 11:46 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Dane Watson <dwatson@alliancecg.net>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa,

Attached is the file with a couple of additional page reference corrections I made. We are good with Pia's edits.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Wednesday, June 24, 2020 7:18 AM
To: Rhonda Watts; Dane Watson
Cc: Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: FW: Depreciation Study and Testimony

Rhonda/Dane,

Pia had the attached final edits to Dane's testimony. Let me know if you have any concerns. Otherwise, we will be final final.

Thanks,
Melissa

From: Powers, Pia K <Pia.Powers@duke-energy.com>
Sent: Tuesday, June 23, 2020 6:33 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise

From:	Rhonda Watts
To:	Abernathy, Melissa Brammer
Cc:	Lepisto, Denise; Gogea, Elena; Raiford, David
Subject:	[EXTERNAL] RE: Depreciation Study and Testimony
Date:	Tuesday, June 23, 2020 4:06:23 PM
Attachments:	image001.png Exhibit DAW-2 PNG Tennessee Depreciation Study Report.pdf PNG Tennessee Depreciation Study Report Final.docx PNG Tennessee Depreciation Study Report Final.pdf

OK, so let's try these. There is no difference between Exhibit DAW-2 and the other PDF other than naming. Thought it might be easier to keep one for the files and use the other for filing.

Good review, I was surprised the spell check didn't pick up at least one or two of these.

Hopefully this takes care of it, if you see something else, let me know.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Tuesday, June 23, 2020 1:45 PM
To: Rhonda Watts
Cc: Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony
Importance: High

Rhonda –

We have looked these over – there are only a few other minor edits that seem to be needed to the narrative and I think are just a result of edits being made. Can you take a look and make these changes quickly today? All appendices look good.

- Report pg 1- last sentence-" There are a number regulator stations on the transmission and distributions systems located across the service area where the pressure of the natural gas is reduced in order to meet system volume requirements. Suggest "there are a number OF regulator stations…"
- Pg 26 in Word doc, Pg 21 Report under heading Account 263.30 Compressor Equipment- per Word doc "in accordance with *standard* accounting practices", PDF says "in accordance with *current* accounting practices"
- Pg 31 in Word doc, Pg 25 in Report, last paragraph under Account 267.00 Mains- this sentence doesn't make sense: "cathodic protection was typically not applied to pipelines until the 1960s or later and external corrosion degradation many have contributed to a shorter life". I believe MANY was intended to be MAY.
- Report page 34 under Account 280.00 Services-bottom of 2nd paragraph- no space between 2020 and tornadoes
- Report page 35 under Account 281 Meters-last sentence- "Some meter groups (meter families) have failed in the past and been accordingly been replaced, but Company personnel would not expect a materially different life from existing. " . Suggest- 'and have accordingly been

replaced"

- Report page 37- second paragraph: "Discussions with Company personnel indicated that a pilot investment of approximately 500 meters using Itron 500G technology that is being considered by the Company." Suggest removal of the word 'that' as it pertains to a sentence that was struck in revision.

These are not major changes, so if you don't think you can make them today, we may just consider what you sent as Final, but wanted to run it by you.

Thanks,
Melissa

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Tuesday, June 23, 2020 11:48 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Dane Watson <dwatson@alliancecg.net>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa and Denise,

Thanks for the quick turnaround on information for the footnote and confirming with Pia. Attached is the Final Report. I am also attaching the native documents as well. Also attached, in word, is Dane's Final testimony and an excel file and PDF of his testimony experience, which is Exhibit DAW-1 and for ease a PDF named Exhibit DAW-2 (Study Report).

Let us know if you need something additional.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Tuesday, June 23, 2020 8:26 AM
To: Rhonda Watts; Dane Watson
Cc: Lepisto, Denise; Raiford, David; Gogea, Elena
Subject: FW: Depreciation Study and Testimony

Rhonda,

FYI – see Pia's note around the footnote and detail – hopefully this helps.

From: Powers, Pia K <Pia.Powers@duke-energy.com>
Sent: Tuesday, June 23, 2020 9:19 AM

To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Cc: Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Melissa, I think footnoting that in the study is a good idea, with exactly the detail Denise just put in her email to me. Yes, thank you. Pia

---

From: Abernathy, Melissa Brammer
Sent: Tuesday, June 23, 2020 8:56 AM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Cc: Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Pia – based on this, do you think Rhonda needs to footnote the amount in the depreciation study to explain the difference? Or we will just be prepared to explain if we get asked through the rate case process?

From: Powers, Pia K <Pia.Powers@duke-energy.com>
Sent: Tuesday, June 23, 2020 8:40 AM
To: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Cc: Raiford, David <David.Raiford@duke-energy.com>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Thank you, Denise.

From: Lepisto, Denise
Sent: Tuesday, June 23, 2020 8:34 AM
To: Powers, Pia K <Pia.Powers@duke-energy.com>
Cc: Raiford, David <David.Raiford@duke-energy.com>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

Pia,

Below is the detail on the CNG I provided to Rhonda Watts at Alliance. Let me know if you have any questions or concerns on how I traced the individual items to amounts referenced in docket 14-00086.

I believe we already discussed most of these assets currently sit in the tools account 294 – They wouldn't move to the CNG account 29002 after the study is approved with a new rate/curve/life.

Denise

From: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Sent: Tuesday, June 23, 2020 7:55 AM
To: Rhonda Watts <rwatts@alliancecg.net>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Good Morning Rhonda,

Here is the detail I think you are looking for;

$327,662 was the building and that was placed into service Jun 2010 –
$4,738,298.91 was the "new" investment of $4.7 million referenced in Docket 14-00086, this was placed into service 2012-2014.

These 2 numbers give us the $5.0 million investment referenced on page 7 of testimony for Docket 14-00086. The actual total is $5,065,960.88 to tie to the $5.1 million referenced below.

Please let me know if you need further detail.

Denise

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Monday, June 22, 2020 10:46 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

I had some recollection of the amount being a little different but couldn't remember specifics. Once I get that information, I can finalize the report and get it returned to you as promised. Unless I hear differently, I will footnote as Pia suggested.

Have a good evening.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Monday, June 22, 2020 9:33 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: Re: Depreciation Study and Testimony

I believe Denise knows the difference from when we researched. I think the 4.7 was the investment they were adding to CNG and there was already a small amount prior to that to get to 5.1.

Denise, please look into this first thing in AM.

Get Outlook for iOS

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Monday, June 22, 2020 6:41:19 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa,

As Dane and I were reviewing a couple of the comments/edits, we came upon Pia's comment regarding the balance of CNG equipment. See below. I know your team evaluated and provided the detail that is included in the attached Accrual workpaper tab for "Reclass of CNG Equipment", but I do not have enough information to footnote why there is a difference, so I need your help here.

Account 290.02 CNG Equipment (25 R3)
This account consists of station structures and improvements, storage cylinders, compressors, dryers, priority panels, and dispensers used at the Company's CNG refueling stations. Currently, there is about $5.1 million [PPK1] in this account, which includes only approved rate base assets. There is no approved life or dispersion curve for this account.

If we need to discuss live, let me know.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Monday, June 22, 2020 2:42 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Meant to respond – looks like it is now fixed in this PDF.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 3:19 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

See how this Appendix B looks.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 1:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Example of header we see in the PDF:

PIEDMONT NATURAL GAS
TENNESSEE
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2019

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 2:26 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Sorry, some issues came up and the call is going longer, can we postpone the call for 10 minutes?

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 12:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Rhonda – Elena and I can chat – what works for you? I'm free at 2:30 EST if you are that quick. Otherwise, let us know some windows.

Thanks!

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 11:50 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>

Subject: [EXTERNAL] RE: Depreciation Study and Testimony

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Melissa,

In regard to Account 266.20, that is the account we transferred to 269.00. My question is, should we put it in Appendix A and footnote " if assets are added to use the whole life rate (1/ASL)", which we have the parameter in Appendix C? My thoughts are it might get used in the future and this way, you would have an approved rate. Otherwise, I would recommend deleting it from Appendix C. Please let me know what you prefer.

Also, I think I need to understand the note from Quynh regarding depreciation expense amounts and the changes that were made in the report in this regard, as it does not match up with our study Appendix A then. Even with the plant balance additions to Appendix A, those are either fully depreciated (Intangibles), Land, and an ARO of which are non-depreciable and/or have no rates, so I am unclear on how the accrual amount changes from what we calculated on Appendix A.

Last, who is best person to discuss the items at the bottom of the word document labeled "Items below to send to Alliance"? I think a quick call would make it easier to clear up a few of the questions I have.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 7:17 AM
To: Rhonda Watts; Dane Watson; Lepisto, Denise; Gogea, Elena
Cc: Raiford, David
Subject: RE: Depreciation Study and Testimony
Importance: High

Rhonda/Dane,

The Piedmont team has reviewed the Depreciation Study and have a few suggested edits/comments. Please see the attached word document with suggestions in tracked changes.

Also, the word document "PNG TN 2019 Depreciation Study Comments" file has comments related to the Appendices. The two main ones are that it appears when the appendices were converted to PDF some of the end of the lines fell off, so not sure if there's a different way to incorporate? Also, similar to NC, there is a desire to have all accounts listed on Appendix A so that it's a complete list even for accounts with $0 that weren't studied. We've attached an excel file with the balances to add in. Perhaps there's one more tickmark to add to those that they weren't studied as part of the study and

the rates should be 0.

Please let me know your thoughts and if we can get revised files early next week would be great.

Thanks!
Melissa

From: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Sent: Tuesday, June 9, 2020 5:54 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Hager, Laura M. <Laura.Hager@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

I just received these from Dane. I have not looked at the files yet. I know you all were waiting on these, so I thought I would send them right over.

Melissa, I will save these in the Depr Study folder

Denise

[PPK1]This amount was ordered by the TPUC in Docket 14-00086, to be $4.7 million, not $5.1 million. See the notes I most recently shared via email on 3/23/2020. If there is a strong reason to use $5.1 instead of $4.7 here, perhaps it can be footnoted here why the $5.1 is different than the $4.7 million.

From: Abernathy, Melissa Brammer
Sent: Wednesday, June 24, 2020 12:31 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

See attached for final Testimony for Dane.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Wednesday, June 24, 2020 11:46 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Dane Watson <dwatson@alliancecg.net>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa,

Attached is the file with a couple of additional page reference corrections I made. We are good with Pia's edits.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Wednesday, June 24, 2020 7:18 AM
To: Rhonda Watts; Dane Watson
Cc: Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: FW: Depreciation Study and Testimony

Rhonda/Dane,

Pia had the attached final edits to Dane's testimony. Let me know if you have any concerns. Otherwise, we will be final final.

Thanks,
Melissa

From: Powers, Pia K <Pia.Powers@duke-energy.com>
Sent: Tuesday, June 23, 2020 6:33 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise

<Denise.Lepisto@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Cc: Hager, Laura M. <Laura.Hager@duke-energy.com>; Couzens, Kally <Kally.Couzens@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Melissa,

I final a final few edits to Dane's testimony. See attached. All else looks good.

I appreciate all the support from you and your team on this matter.

Thank you,
Pia

From: Bowman, Quynh Pham
Sent: Tuesday, June 23, 2020 5:44 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>
Cc: Hager, Laura M. <Laura.Hager@duke-energy.com>; Couzens, Kally <Kally.Couzens@duke-energy.com>
Subject: FW: Depreciation Study and Testimony
Importance: High

Final versions

From: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Sent: Tuesday, June 23, 2020 5:41 PM
To: Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Gogea, Elena <Elena.Gogea@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: FW: Depreciation Study and Testimony
Importance: High

Quynh,

Here is the Final PDF of the Depreciation Study. I've also included final Word Version of the Testimony as well as the two exhibits. We have these files in Excel and Word too where appropriate.

Let me know which formats you need.

Thanks.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Tuesday, June 23, 2020 4:04 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-

energy.com>; Raiford, David <David.Raiford@duke-energy.com>
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Let us know if you need something additional.

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Sent: Tuesday, June 23, 2020 8:26 AM
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Cc: Lepisto, Denise; Raiford, David; Gogea, Elena
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Cc: Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>

Subject: RE: Depreciation Study and Testimony

Melissa, I think footnoting that in the study is a good idea, with exactly the detail Denise just put in her email to me. Yes, thank you. Pia

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Sent: Tuesday, June 23, 2020 8:56 AM
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Cc: Raiford, David <David.Raiford@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Pia – based on this, do you think Rhonda needs to footnote the amount in the depreciation study to explain the difference? Or we will just be prepared to explain if we get asked through the rate case process?

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Cc: Raiford, David <David.Raiford@duke-energy.com>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
Subject: RE: Depreciation Study and Testimony

Thank you, Denise.

From: Lepisto, Denise
Sent: Tuesday, June 23, 2020 8:34 AM
To: Powers, Pia K <Pia.Powers@duke-energy.com>
Cc: Raiford, David <David.Raiford@duke-energy.com>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>
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Pia,

Below is the detail on the CNG I provided to Rhonda Watts at Alliance. Let me know if you have any questions or concerns on how I traced the individual items to amounts referenced in docket 14-00086.

I believe we already discussed most of these assets currently sit in the tools account 294 – They wouldn't move to the CNG account 29002 after the study is approved with a new rate/curve/life.

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To: Rhonda Watts <rwatts@alliancecg.net>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
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Good Morning Rhonda,

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$327,662 was the building and that was placed into service Jun 2010 –
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These 2 numbers give us the $5.0 million investment referenced on page 7 of testimony for Docket 14-00086. The actual total is $5,065,960.88 to tie to the $5.1 million referenced below.

Please let me know if you need further detail.

Denise

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To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

I had some recollection of the amount being a little different but couldn't remember specifics. Once I get that information, I can finalize the report and get it returned to you as promised. Unless I hear differently, I will footnote as Pia suggested.

Have a good evening.

Thanks,
Rhonda

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Subject: Re: Depreciation Study and Testimony

I believe Denise knows the difference from when we researched. I think the 4.7 was the investment they were adding to CNG and there was already a small amount prior to that to get to 5.1.

Denise, please look into this first thing in AM.

Get Outlook for iOS

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Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa,

As Dane and I were reviewing a couple of the comments/edits, we came upon Pia's comment regarding the balance of CNG equipment. See below. I know your team evaluated and provided the detail that is included in the attached Accrual workpaper tab for "Reclass of CNG Equipment", but I do not have enough information to footnote why there is a difference, so I need your help here.

Account 290.02 CNG Equipment (25 R3)
This account consists of station structures and improvements, storage cylinders, compressors, dryers, priority panels, and dispensers used at the Company's CNG refueling stations. Currently, there is about $5.1 million [PPK1] in this account, which includes only approved rate base assets. There is no approved life or dispersion curve for this account.

If we need to discuss live, let me know.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Monday, June 22, 2020 2:42 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Meant to respond – looks like it is now fixed in this PDF.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 3:19 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

See how this Appendix B looks.

Thanks,

Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 1:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Example of header we see in the PDF:

PIEDMONT NATURAL GAS
TENNESSEE
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2019

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 2:26 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Sorry, some issues came up and the call is going longer, can we postpone the call for 10 minutes?

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 12:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Rhonda – Elena and I can chat – what works for you? I'm free at 2:30 EST if you are that quick. Otherwise, let us know some windows.

Thanks!

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 11:50 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Melissa,

In regard to Account 266.20, that is the account we transferred to 269.00. My question is, should we put it in Appendix A and footnote " if assets are added to use the whole life rate (1/ASL)", which we have the parameter in Appendix C? My thoughts are it might get used in the future and this way, you would have an approved rate. Otherwise, I would recommend deleting it from Appendix C. Please let me know what you prefer.

Also, I think I need to understand the note from Quynh regarding depreciation expense amounts and the changes that were made in the report in this regard, as it does not match up with our study Appendix A then. Even with the plant balance additions to Appendix A, those are either fully depreciated (Intangibles), Land, and an ARO of which are non-depreciable and/or have no rates, so I am unclear on how the accrual amount changes from what we calculated on Appendix A.

Last, who is best person to discuss the items at the bottom of the word document labeled "Items below to send to Alliance"? I think a quick call would make it easier to clear up a few of the questions I have.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 7:17 AM
To: Rhonda Watts; Dane Watson; Lepisto, Denise; Gogea, Elena
Cc: Raiford, David
Subject: RE: Depreciation Study and Testimony
Importance: High

Rhonda/Dane,

The Piedmont team has reviewed the Depreciation Study and have a few suggested edits/comments. Please see the attached word document with suggestions in tracked changes.

Also, the word document "PNG TN 2019 Depreciation Study Comments" file has comments related to the Appendices. The two main ones are that it appears when the appendices were converted to PDF some of the end of the lines fell off, so not sure if there's a different way to incorporate? Also, similar to NC, there is a desire to have all accounts listed on Appendix A so that it's a complete list even for accounts with $0 that weren't studied. We've attached an excel file with the balances to add in. Perhaps there's one more tickmark to add to those that they weren't studied as part of the study and the rates should be 0.

Please let me know your thoughts and if we can get revised files early next week would be great.

From:	Rhonda Watts
To:	Abernathy, Melissa Brammer
Cc:	Lepisto, Denise; Gogea, Elena; Raiford, David
Subject:	[EXTERNAL] RE: Depreciation Study and Testimony
Date:	Tuesday, June 23, 2020 4:06:23 PM
Attachments:	image001.png Exhibit DAW-2 PNG Tennessee Depreciation Study Report.pdf PNG Tennessee Depreciation Study Report Final.docx PNG Tennessee Depreciation Study Report Final.pdf

OK, so let's try these. There is no difference between Exhibit DAW-2 and the other PDF other than naming. Thought it might be easier to keep one for the files and use the other for filing.

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Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Melissa,

As Dane and I were reviewing a couple of the comments/edits, we came upon Pia's comment regarding the balance of CNG equipment. See below. I know your team evaluated and provided the detail that is included in the attached Accrual workpaper tab for "Reclass of CNG Equipment", but I do not have enough information to footnote why there is a difference, so I need your help here.

Account 290.02 CNG Equipment (25 R3)
This account consists of station structures and improvements, storage cylinders, compressors, dryers, priority panels, and dispensers used at the Company's CNG refueling stations. Currently, there is about $5.1 million [PPK1] in this account, which includes only approved rate base assets. There is no approved life or dispersion curve for this account.

If we need to discuss live, let me know.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Monday, June 22, 2020 2:42 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Meant to respond – looks like it is now fixed in this PDF.

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 3:19 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

See how this Appendix B looks.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 1:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Example of header we see in the PDF:

PIEDMONT NATURAL GAS
TENNESSEE
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2019

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 2:26 PM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>
Subject: [EXTERNAL] RE: Depreciation Study and Testimony

Sorry, some issues came up and the call is going longer, can we postpone the call for 10 minutes?

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 12:51 PM
To: Rhonda Watts; Lepisto, Denise; Gogea, Elena; Raiford, David
Subject: RE: Depreciation Study and Testimony

Rhonda – Elena and I can chat – what works for you? I'm free at 2:30 EST if you are that quick. Otherwise, let us know some windows.

Thanks!

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, June 18, 2020 11:50 AM
To: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>; Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Gogea, Elena <Elena.Gogea@duke-energy.com>; Raiford, David <David.Raiford@duke-energy.com>

Subject: [EXTERNAL] RE: Depreciation Study and Testimony

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Melissa,

In regard to Account 266.20, that is the account we transferred to 269.00. My question is, should we put it in Appendix A and footnote " if assets are added to use the whole life rate (1/ASL)", which we have the parameter in Appendix C? My thoughts are it might get used in the future and this way, you would have an approved rate. Otherwise, I would recommend deleting it from Appendix C. Please let me know what you prefer.

Also, I think I need to understand the note from Quynh regarding depreciation expense amounts and the changes that were made in the report in this regard, as it does not match up with our study Appendix A then. Even with the plant balance additions to Appendix A, those are either fully depreciated (Intangibles), Land, and an ARO of which are non-depreciable and/or have no rates, so I am unclear on how the accrual amount changes from what we calculated on Appendix A.

Last, who is best person to discuss the items at the bottom of the word document labeled "Items below to send to Alliance"? I think a quick call would make it easier to clear up a few of the questions I have.

Thanks,
Rhonda

From: Abernathy, Melissa Brammer [mailto:Melissa.Abernathy@duke-energy.com]
Sent: Thursday, June 18, 2020 7:17 AM
To: Rhonda Watts; Dane Watson; Lepisto, Denise; Gogea, Elena
Cc: Raiford, David
Subject: RE: Depreciation Study and Testimony
Importance: High

Rhonda/Dane,

The Piedmont team has reviewed the Depreciation Study and have a few suggested edits/comments. Please see the attached word document with suggestions in tracked changes.

Also, the word document "PNG TN 2019 Depreciation Study Comments" file has comments related to the Appendices. The two main ones are that it appears when the appendices were converted to PDF some of the end of the lines fell off, so not sure if there's a different way to incorporate? Also, similar to NC, there is a desire to have all accounts listed on Appendix A so that it's a complete list even for accounts with $0 that weren't studied. We've attached an excel file with the balances to add in. Perhaps there's one more tickmark to add to those that they weren't studied as part of the study and

the rates should be 0.

Please let me know your thoughts and if we can get revised files early next week would be great.

Thanks!
Melissa

From: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Sent: Tuesday, June 9, 2020 5:54 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Hager, Laura M. <Laura.Hager@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

I just received these from Dane. I have not looked at the files yet. I know you all were waiting on these, so I thought I would send them right over.

Melissa, I will save these in the Depr Study folder

Denise

[PPK1]This amount was ordered by the TPUC in Docket 14-00086, to be $4.7 million, not $5.1 million. See the notes I most recently shared via email on 3/23/2020. If there is a strong reason to use $5.1 instead of $4.7 here, perhaps it can be footnoted here why the $5.1 is different than the $4.7 million.

From: Dane Watson
To: Burnes, Wendy
Cc: Lepisto, Denise; Abernathy, Melissa Brammer; Rhonda Watts
Subject: RE: PNG TN Depr Study - Meter meeting
Date: Thursday, March 19, 2020 2:36:33 PM

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Wendy,
Some example questions are below.
Do you repair meters?
What is the operational process for retiring meters? Would loop be replaced with pulling a meter?
What type of meter testing do you do? Have there been significant family failures in recent years?
How many total meters do you have? How many of your meters have ERTs?
When was the initial installation of ERTS and were there a significant number that could not be retrofit?
What is your practice related to the meter when an ERT fails? With the ERT when a meter fails?
What is your life expectation for the various meter types and ERTS?
Do you use premanufactured meter loops? If so, for how long?
Would regulators be normally replaced with the loop? Would the loop be replaced if needing to replace the regulator?
Etc…
Dane

From: Burnes, Wendy <Wendy.Burnes@duke-energy.com>
Sent: Thursday, March 19, 2020 12:59 PM
To: Dane Watson <dwatson@alliancecg.net>; Rhonda Watts <rwatts@alliancecg.net>
Cc: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Subject: PNG TN Depr Study - Meter meeting

Hi Dane/Rhonda,

I'm in the process of scheduling a call with a subject matter expert for meters and would like to make sure we make good use of our time with the correct person. Can you please provide me with some example meter questions so that I can make sure we have the correct subject matter expert on the call?

Thank you,

Wendy Burnes

Thanks!
Melissa

From: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Sent: Tuesday, June 9, 2020 5:54 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>; Hager, Laura M. <Laura.Hager@duke-energy.com>; Bowman, Quynh Pham <Quynh.Bowman@duke-energy.com>
Cc: Abernathy, Melissa Brammer <Melissa.Abernathy@duke-energy.com>
Subject: FW: Depreciation Study and Testimony

I just received these from Dane. I have not looked at the files yet. I know you all were waiting on these, so I thought I would send them right over.

Melissa, I will save these in the Depr Study folder

Denise

[PPK1]This amount was ordered by the TPUC in Docket 14-00086, to be $4.7 million, not $5.1 million. See the notes I most recently shared via email on 3/23/2020. If there is a strong reason to use $5.1 instead of $4.7 here, perhaps it can be footnoted here why the $5.1 is different than the $4.7 million.

From:	Rhonda Watts
To:	Lepisto, Denise; Burnes, Wendy
Subject:	RE: Question on Meters and ERTs and Accounts 282-284
Date:	Tuesday, March 31, 2020 9:44:59 AM

Super – thanks!

From: Lepisto, Denise [mailto:Denise.Lepisto@duke-energy.com]
Sent: Tuesday, March 31, 2020 8:21 AM
To: Rhonda Watts; Burnes, Wendy
Subject: RE: Question on Meters and ERTs and Accounts 282-284

Hi Rhonda,

We'll circle back with you on these items before the end of the day today.

Denise

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Monday, March 30, 2020 11:32 AM
To: Lepisto, Denise <Denise.Lepisto@duke-energy.com>; Burnes, Wendy <Wendy.Burnes@duke-energy.com>
Subject: Question on Meters and ERTs and Accounts 282-284

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Good morning,

Just a couple of follow up questions on Meters, ERTs and then the meter loop (282-284.

Can you check to see about any salvage or cost of removal for Meters and ERTs accounts? Just want to be sure we capture both life and net salvage. When looking back at the Carolina-Corporate net salvage, it appears that salvage and cost of removal was being recorded to Account 281 only.

Also, we did not see any retirements in accounts 282-284 for the last two years (2018 and 2019), is there something going on here that can be addressed? It would be important just like the meters and ERTS to get the salvage and cost of removal. Follow up question, we do not see any salvage (wouldn't really expect much, if any) or cost of removal for 282-284 – when retiring and replacing the meter loop, do they charge any salvage/cost of removal or is it all rolled into the replacement or maybe charged to 281?

From:	Rhonda Watts
To:	Lepisto, Denise
Subject:	RE: Proper Reference
Date:	Thursday, May 21, 2020 4:48:19 PM

Perfect! Thanks!

From: Lepisto, Denise [mailto:Denise.Lepisto@duke-energy.com]
Sent: Thursday, May 21, 2020 3:42 PM
To: Rhonda Watts
Subject: FW: Proper Reference

Here you go.

From: Powers, Pia K <Pia.Powers@duke-energy.com>
Sent: Thursday, May 21, 2020 4:42 PM
To: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Subject: RE: Proper Reference

I think it's best to say that the study was conducted for the Tennessee assets of Piedmont Natural Gas Company, Inc.

From: Lepisto, Denise
Sent: Thursday, May 21, 2020 4:38 PM
To: Powers, Pia K <Pia.Powers@duke-energy.com>
Subject: FW: Proper Reference

Hi Pia,

Can you answer Rhonda's question below?

Thanks.

Denise

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Thursday, May 21, 2020 4:09 PM
To: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Subject: Proper Reference

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senders or unexpected email. ***

Hi Denise,

I may have asked this already, but what is the proper way to reference who we conducted the study for? Do we say Piedmont Natural Gas Tennessee? Or do we need to say Duke Energy, Piedmont Natural Gas, Tennessee Properties? Or some other variation?

Thanks,

Rhonda Watts
Senior Consultant

Alliance Consulting Group
101 E. Park Blvd., Suite 220
Plano, Texas 75074

Cell: (817) 965-0331
Work: (214) 473-6771 ext 16

Thanks,

Rhonda Watts
Senior Consultant

Alliance Consulting Group
101 E. Park Blvd., Suite 220
Plano, Texas 75074

Cell: (817) 965-0331
Work: (214) 473-6771 ext 16

From: Rhonda Watts
To: Lepisto, Denise
Subject: RE: rates questions
Date: Friday, May 15, 2020 5:31:26 PM
Attachments: image001.png

OK. I think from a regulatory view that is probably best decision. I will make that change on 26330 and save as v3 too.

Have a great weekend!

From: Lepisto, Denise [mailto:Denise.Lepisto@duke-energy.com]
Sent: Friday, May 15, 2020 4:15 PM
To: Rhonda Watts
Subject: RE: rates questions

I can't really tell what happened on the 28105.

I just spoke with Melissa and she would like to show what was approved, not necessarily what we are using – especially with the vehicles because it will look weird. We could be overstating if we use a 20% because some of those assets in the vehicle ranges are fully depreciated – I know they have to be because of age.

If you can just change the 3.33%, then I think we are good. No need to send a V4 – I'll just change on my side on V3

From: Rhonda Watts <rwatts@alliancecg.net>
Sent: Friday, May 15, 2020 4:43 PM
To: Lepisto, Denise <Denise.Lepisto@duke-energy.com>
Subject: RE: rates questions

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Glad we tie balances that is a good start. ☺

Now for the other questions:

- Good catch on 26330 – that should be 3.33%. I will make that change in my accrual file.
- 28105 – Do you have the background on why you are using 6.89% instead of the study 8.34%? When I look back we footnoted that the existing then was based on what is being

used from the allocation from Corporate to Tennessee. If that is still the case and 6.89% is that rate, I will footnote like we did previously. You don't want to get caught not using an authorized rate. Doubt they would care, since the 6.89% is less than 8.34%, but you know the principle to follow here.

- 292 – Strangely enough I don't see 292 included in Appendix A, but there is a rate calculation for auto (5 year) and heavy duty (10 year) (two different accounts) but the rate was calculated as if group, 4.55% and 6.11% respectively. On what hand I think it is more appropriate to show what you are using, but it could raise questions. Maybe, another footnote? Like we needed some more. ☺

I will show 28105 and 292 as you direct me. Let me know if there is concern about footnoting if we need to.

Thanks,
Rhonda

From: Lepisto, Denise [mailto:Denise.Lepisto@duke-energy.com]
Sent: Friday, May 15, 2020 3:04 PM
To: Rhonda Watts
Subject: rates questions

Hi Rhonda,
I have a couple of questions – I tied out the study to the data provided – we look good on all that as far as balances. Where I have a question is on the "existing rates" on the Comparison tab- See attached file.

I see a difference in 26330 – my info shows the last study showed 3.33% and that is the rate we are using – should this be 3.33% instead of 3.30%?
In 28105 – the rate from the last study was 8.34% - but we are using 6.89% - should this reflect what we are actually using?
On the vehicles – we are actually using individual depreciation and they have a 5 year life – so 20% - should the rates shown be 20% because that is what we are using.

Thanks!

Denise

Denise Lepisto
Lead Accounting Analyst
Rate Case Support, Asset and Retirement Cost Recovery
(704) 382-6048

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-6. Refer to the testimony and exhibits of Company witness Normand regarding the proposed class cost of service study and rate design recommendations. Provide a copy of Mr. Normand's exhibits and workpapers in Excel format with all formulas intact.

RESPONSE: The Excel workpapers were provided in the Company's response to MFR Item 42.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-7. Refer to the Company's response to MFR #12 regarding the Company's workpapers. Provide a copy of the file "MFR 12 Index.xlsx" (descriptive list of all the other supporting files attached) that is referenced in this response but was not included in the Company's filing.

RESPONSE: Piedmont's counsel emailed MFR Item 12 Index to the Consumer Advocate Division on August 3, 2020 pursuant to the Consumer Advocate's request.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-8. Refer to the "Revenue Requirement TN" tab of the "QPB Exhibits_6-27-2020" spreadsheet that was included with the Company's filing. Specifically refer Cell F135 that computes the Company's proposed revenue conversion factor of 1.339565. Provide the following information related to this calculation.

a. Explain why the Company has omitted forfeited discounts from the revenue conversion factor calculation.

b. Explain why the Company has included a "Commission Fee Factor" within the revenue conversion factor calculation when the TPUC fee for the attrition year is based on current rates.

c. Explain why the Company has included a "Gross Receipts Tax Factor" within the revenue conversion factor calculation when the Gross Receipts Taxes for the attrition year is based on current rates.

RESPONSE:

a. The omission was an oversight.

b. The retention factor is used to properly calculate the additional revenue requirement related to the increase in revenue based on the proposed rates. The Regulatory Commission Fee adjustment uses the amount of attrition period revenues before the proposed change in rates. If the proposed rates are implemented, additional expense is incurred for the Regulatory Commission Fee because revenues would increase.

c. The retention factor is used to properly calculate the additional revenue requirement related to the increase in revenue based on the proposed rates. The Gross Receipts Tax adjustment uses the amount of attrition period revenues before the proposed

change in rates. If the proposed rates are implemented, additional expense is incurred for the Gross Receipts Tax because revenues would increase.

Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-9. Refer to Exhibit PKP-2 which contains a redline copy of the Company's proposed tariff changes. In this Exhibit, it appears that the Company is proposing to delete all references to tariff rates and instead insert language to "Please Refer to Tariff Sheet No. 1". Explain the Company's rationale for deleting the specific base rates from each rate schedule in the Company's tariff. In addition, identify and provide a copy of the Company's proposed Tariff Sheet No. 1.

RESPONSE: Piedmont is proposing to strike the existing numerical rate and charge references shown within each individual Rate Schedule of the Tariff, and to instead simply reference "Tariff Sheet No. 1" therein. Presently, each Rate Schedule in the Tariff lists the amount of the Monthly Charge, the base margin rate component per therm ("Commodity Charge") and, where applicable, the base margin demand rate component per therm ("Demand Charge").

Tariff Sheet No. 1 is already a part of Piedmont's Commission-approved Tennessee Tariff. Currently in effect is "Sixty-Sixth Revised Sheet No. 1", which became effective September 1, 2020.*

Column <1> in Tariff Sheet No. 1 shows the amount of the monthly charge, the base margin rate component per therm and, where applicable, the base margin demand rate component per therm. Additionally, Tariff Sheet No. 1 shows in columnar format all the other rate components for each Rate Schedule, and a summary column with the total billing rate applicable for each Rate Schedule.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD DR 1 Item 9

Tariff Sheet No. 1

Sixty-Sixth Revised Sheet No. 1

PIEDMONT NATURAL GAS COMPANY, INC.
Tennessee Service Territory
Billing Rates Effective: January 1, 2021

Rate Schedule	Description	Tariff Base Rate Approved in Docket No. 20-____	Cumulative PGA Demand	Cumulative PGA Commodity	Current ACA Demand	Current ACA Commodity	Current IPA	Current IM Adjustment	Temporary Decrements Approved in Docket No.18-00040: Deferred Base Revenue Refund	Temporary Decrements Approved in Docket No.18-00040: Unprotected Excess ADIT Refund	Total Adj. Factor (Sum Col.2 thru Col.8)	Proposed Billing Rate (Col.1+Col.9)
		<1>	<2>	<3>	<4a>	<4b>	<5>	<6>	<7>	<8>	<9>	<10>
	Monthly Charge-Nov.-Mar.	$17.45										$17.45
Residential	Monthly Charge-Apr.-Oct.	$13.45										$13.45
301	Nov.- Mar. per TH	0.63264	0.07823	0.19717	(0.01181)	(0.01044)	0.00822	(0.03348)	(0.01958)	(0.04211)	0.16620	0.79884
301	Apr.- Oct. per TH	0.52360	0.07823	0.19717	(0.01181)	(0.01044)	0.00822	(0.03348)	(0.01958)	(0.04211)	0.16620	0.68980
Small General	Monthly Charge	$44.00										$44.00
302	Nov.- Mar. per TH	0.56988	0.07323	0.19717	(0.01181)	(0.01044)	0.00822	(0.02925)	(0.01710)	(0.03678)	0.17324	0.74312
302	Apr.- Oct. per TH	0.47602	0.07323	0.19717	(0.01181)	(0.01044)	0.00822	(0.02925)	(0.01710)	(0.03678)	0.17324	0.64926
Medium General	Monthly Charge	$300.00										$300.00
352	Nov.- Mar. per TH	0.50853	0.07394	0.19717	(0.01181)	(0.01044)	0.00822	(0.02925)	(0.01710)	(0.03678)	0.17395	0.68248
352	Apr.- Oct. per TH	0.42478	0.07394	0.19717	(0.01181)	(0.01044)	0.00822	(0.02925)	(0.01710)	(0.03678)	0.17395	0.59873
Motor Vehicle Fuel	Monthly Charge	varies by customer per their corresponding rate schedule										
343	Nov.- Mar. per TH	varies by customer per their corresponding rate schedule										
343	Apr.- Oct. per TH	varies by customer per their corresponding rate schedule										
303	Monthly Charge	$800.00										$800.00
Firm	Demand Charge per TH	1.00000	0.67158		(0.18957)						0.48201	1.48201
General Sales	First 15,000 TH/TH	0.17560		0.19717		(0.01044)	0.00822	(0.01299)	(0.00319)	(0.00685)	0.17192	0.34752
	Next 25,000 TH/TH	0.16168		0.19717		(0.01044)	0.00822	(0.01299)	(0.00319)	(0.00685)	0.17192	0.33360
	Next 50,000 TH/TH	0.11388		0.19717		(0.01044)	0.00822	(0.01299)	(0.00319)	(0.00685)	0.17192	0.28580
	Over 90,000 TH/TH	0.04349		0.19717		(0.01044)	0.00822	(0.01299)	(0.00319)	(0.00685)	0.17192	0.21541
304	Monthly Charge	$800.00										$800.00
Interruptible	First 15,000 TH/TH	0.14579		0.19717		(0.01044)	0.00822	(0.00325)	(0.00319)	(0.00685)	0.18166	0.32745
General Sales	Next 25,000 TH/TH	0.13423		0.19717		(0.01044)	0.00822	(0.00325)	(0.00319)	(0.00685)	0.18166	0.31589
	Next 50,000 TH/TH	0.09454		0.19717		(0.01044)	0.00822	(0.00325)	(0.00319)	(0.00685)	0.18166	0.27620
	Over 90,000 TH/TH	0.03610		0.19717		(0.01044)	0.00822	(0.00325)	(0.00319)	(0.00685)	0.18166	0.21776
313	Monthly Charge	$800.00										$800.00
Firm	Demand Charge per TH	1.00000	0.83617		(0.18957)						0.64660	1.64660
Transportation	First 15,000 TH/TH	0.17560						(0.01299)	(0.00319)	(0.00685)	(0.02303)	0.15257
	Next 25,000 TH/TH	0.16168						(0.01299)	(0.00319)	(0.00685)	(0.02303)	0.13865
	Next 50,000 TH/TH	0.11388						(0.01299)	(0.00319)	(0.00685)	(0.02303)	0.09085
	Over 90,000 TH/TH	0.04349						(0.01299)	(0.00319)	(0.00685)	(0.02303)	0.02046
314	Monthly Charge	$800.00										$800.00
Interruptible	First 15,000 TH/TH	0.14579						(0.00325)	(0.00319)	(0.00685)	(0.01329)	0.13250
Transportation	Next 25,000 TH/TH	0.13423						(0.00325)	(0.00319)	(0.00685)	(0.01329)	0.12094
	Next 50,000 TH/TH	0.09454						(0.00325)	(0.00319)	(0.00685)	(0.01329)	0.08125
	Over 90,000 TH/TH	0.03610						(0.00325)	(0.00319)	(0.00685)	(0.01329)	0.02281
310	Demand Charge per TH	0.96000	0.13372		(0.18957)						(0.05585)	0.90415
Resale Service	Commodity Charge	0.47742		0.19717		(0.01044)	0.00822	(0.01299)	(0.00970)	(0.02086)	0.15140	0.62882

NOTES:

In accordance with the Tennessee Public Service Commission order in Docket U-7074 customers metered inside Davidson County are required to pay an additional 6.25% for collection of the Metro Franchise Fee. Customers served by the Ashland City, Fairview, Greenbrier, Hartsville, Mt. Juliet and White House systems are required to pay 5.0%. Customers served by the Franklin and Nolensville systems are required to pay 3%.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

The rationale for this proposed Tariff change is to improve Piedmont's Tariff by removing duplicative and partial references, thereby yielding a more streamlined and cohesive document overall.

Proposed "Tariff Sheet No. 1" was presented in Exhibit_(KAC-4) in the direct testimony of Piedmont witness Kally Couzens and is attached hereto.

* Sixty-Sixth Revised Sheet No. 1 became effective September 1, 2020. Compared to the previously effective version of Tariff Sheet No. 1, the Sixty-Sixth Revised version amended the footnote in order to update the reference to the franchise fee for customers within the City of Franklin. The Franklin franchise fee rate to customers changed pursuant to the Negotiated Franchise Agreement with the Franklin, Tennessee that was approved by the TPUC on August 10, 2020 in Docket No. 20-00078.

Name and Title of Preparer: Pia Powers, Managing Director - Gas Rates and Regulatory
Name and Title of Responsible Person: Pia Powers, Managing Director - Gas Rates and Regulatory

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
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1-10. Refer to the "O&M Summary Schedule" tab of the "Revenue Requirement Summary" spreadsheet that was included with the Company's filing. Specifically refer Cell G39 of this spreadsheet that computes the Company's Accounting/Ratemaking Adjustments for Income Taxes. Provide a copy of the "Revenue Requirement.xlsx" spreadsheet referenced in the formula for this cell. In addition, provide a copy of all Company workpapers in Excel format with formulas intact that were used to prepare the current rate case that have not already been submitted.

RESPONSE: See attachment.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-11. Refer to the "30 Yr Avg" tab of the "SW Revenue Pro Forma _HDD NOAA Source Data" spreadsheet included with the Company's filing. Specifically refer to Cell AK110 of this spreadsheet which computes 306.10 as the cycle (aggregate from the 16th of the previous month to the 15th of the current month) normal heating degree days for April. Confirm and explain the Company's rationale for using the 30-year period ending March 2019 as a component for this calculation instead of the 30-year period ended March 2020.

RESPONSE: To compute monthly bill cycle heating degree days, Piedmont aggregates the daily heating degree days from the 16th of the previous month to the 15th of the current month. The computation of normal heating degree days, which uses a thirty-year average of daily heating degree days, simply follows this same monthly bill cycle timing rather than calendar month timing. For the month of April 2019, the first month of the Test Period, the Company computed normal daily heating degree days starting March 16th and ending April 15th using the previous thirty years (1990 to 2019) of actual heating degree days. Subsequent Test Period months were computed in the same manner using the previous thirty years of actual data for the respective bill cycle period.

Preparer: Kally Couzens, Manager - Rates & Regulatory Strategy

Responsible Person: Kally Couzens, Manager - Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
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1-12. Refer to the "30 Yr Avg" tab of the "SW Revenue Pro Forma _HDD NOAA Source Data" spreadsheet included with the Company's filing. Specifically refer to Cell AK79 of this spreadsheet which computes 521.20 as the cycle (aggregate from the 16th of the previous month to the 15th of the current month) normal heating degree days for March. Confirm and explain the Company's rationale for using the 30-year average heating degree days of 15.90 for February 29th (leap day) as a component for this calculation instead of adjusting this amount to reflect that leap day only occurs once every 4 years.

RESPONSE: The thirty-year average heating degree days of 15.90 for February 29th (leap day) was computed by taking an average of the eight leap days that occurred from 1991 to 2020. The heating degree days for February 29th should have been adjusted to reflect that leap year occurs once every four years.

Name and Title of Preparer: Kally Couzens, Manager - Rates & Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-13. Refer to the "Residential _301" tab of the "1_Sales and Transportation Pro Forma Revenue -CONFIDENTIAL" spreadsheet included with the Company's filing. Specifically refer to Cell J9 of this spreadsheet which includes a note referring to the Company's 620B Reports. Provide a complete copy of the Company's monthly 620B Reports in Excel and PDF format from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

RESPONSE: Please see the 2 attachments.

Name and Title of Preparer: Doug Templeton - Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Kally Couzens - Manager Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

Piedmont Natural Gas Company, Inc.

620B Reports

Rate Key		
Description	Current Tariff Rate Schedule	Billing System Rate Code [1]
Residential Service	301	301/311/313
Small General Service	302	302/321/332
Medium General Service	352	352/366
Firm General Sales Service	303	331
Interruptible General Sales Service	304	341
Firm Transportation Service	313	371
Interruptible Transportation Service	314	372
Resale Service	310	381
Other System Tracking Rate Codes:		
Cash-out (off cycle)		328
Motor Vehicle Fuel *(prior to Mar 2015)*		342
Secondary Marketing		360
Emergency Service		361
Standby Sales		362
Cash-out		365
Special Contract		373

1/ Certain reports and queries run from the Piedmont billing system (such as 620B and 301C) reflect billing system rate codes, which may vary from those rate codes reflected in Piedmont's Tariff Rate Schedules.

The data for Tariff Rate Schedule 343 - Motor Vehicle Fuel Service is reflected in the corresponding billing rate schedule.

6/4/2011 12.53.19 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-11

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	49,292	2,014,395
311		49,292	2,014,395
313	802	100,176	1,806,418
313		100,176	1,806,418
321	811	12,372	582,124
321		12,372	582,124
328	952	1	73,445
328		1	73,445
331	811	24	177,766
331	812	17	114,111
331		41	291,877
332	810	3,964	1,678,595
332	811	48	14,288
332		4,012	1,692,883
341	812	2	4,460
341		2	4,460
352	811	264	239,458
352		264	239,458
365	953	8	-923,545
365		8	-923,545
366	810	140	478,615
366	811	1	12,796
366		141	491,411

6/4/2011 12.53.19 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	66	715,699
371		893	22	1,620,322
371			88	2,336,021
372		892	19	2,240,980
372		893	33	2,134,501
372			52	4,375,481
373		893	2	1,777,387
373			2	1,777,387
381		831	3	2,138
381			3	2,138
STATE	TOTAL:		166,454	14,763,953

7/7/2011 06.33.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-11

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	49,282	1,550,656
311		49,282	1,550,656
313	802	99,430	1,041,208
313		99,430	1,041,208
321	811	12,528	296,642
321		12,528	296,642
331	811	25	144,252
331	812	16	79,867
331		41	224,119
332	810	3,660	1,509,139
332	811	14	2,802
332		3,674	1,511,941
341	812	2	
341		2	
352	811	337	154,096
352		337	154,096
365	953	8	44,524
365		8	44,524
366	810	145	472,707
366		145	472,707
371	892	65	530,547
371	893	23	1,511,648
371		88	2,042,195

7/7/2011 06.33.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	1,950,615
372		893	34	1,922,955
372			53	3,873,570
373		893	2	1,596,799
373			2	1,596,799
381		831	3	1,208
381			3	1,208
STATE	TOTAL:		165,593	12,809,665

8/4/2011 06.27.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-11

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	49,235	1,140,639
311		49,235	1,140,639
313	802	98,613	599,483
313		98,613	599,483
321	811	12,480	174,314
321		12,480	174,314
331	811	25	133,864
331	812	16	74,428
331		41	208,292
332	810	3,643	1,377,877
332	811	16	3,265
332		3,659	1,381,142
341	812	2	
341		2	
352	811	342	102,796
352		342	102,796
360	953	1	116,040
360		1	116,040
365	953	8	434,732
365		8	434,732
366	810	143	425,245
366		143	425,245
371	892	66	477,228

8/4/2011 06.27.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	23	1,478,020
371			89	1,955,248
372		892	19	2,128,999
372		893	34	1,816,255
372			53	3,945,254
373		893	2	1,597,307
373			2	1,597,307
381		831	3	1,099
381			3	1,099
STATE	TOTAL:		164,671	12,081,591

9/7/2011 06.39.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
311		801	49,294	972,743
311			49,294	972,743
313		802	98,251	523,483
313			98,251	523,483
321		811	12,410	153,106
321			12,410	153,106
328		952	1	1,911
328			1	1,911
331		811	25	148,187
331		812	16	74,027
331			41	222,214
332		810	3,632	1,269,272
332		811	18	3,902
332			3,650	1,273,174
341		812	2	
341			2	
352		811	341	99,283
352			341	99,283
365		953	8	34,110
365			8	34,110
366		810	143	372,555
366			143	372,555
371		892	65	501,942

9/7/2011 06.39.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	23	1,566,406
371			88	2,068,348
372		892	19	2,107,699
372		893	34	2,335,950
372			53	4,443,649
373		893	2	641,505
373			2	641,505
381		831	3	1,210
381			3	1,210
STATE	TOTAL:		164,287	10,807,291

10/6/2011 06.38.18 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS
FOR THE MONTH: Sep-11

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	49,418	1,144,219
311		49,418	1,144,219
313	802	98,081	597,120
313		98,081	597,120
321	811	12,391	213,683
321		12,391	213,683
331	811	25	183,202
331	812	16	94,776
331		41	277,978
332	810	3,634	1,403,302
332	811	23	5,589
332		3,657	1,408,891
341	812	2	2,400
341		2	2,400
352	811	340	147,891
352		340	147,891
362	953	1	1,843
362		1	1,843
365	953	7	69,985
365		7	69,985
366	810	143	445,750
366		143	445,750
371	892	65	617,620

10/6/2011 06.38.18 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS
FOR THE MONTH: Sep-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	23	1,535,046
371			88	2,152,666
372		892	19	2,260,479
372		893	34	2,503,023
372			53	4,763,502
373		893	2	378,515
373			2	378,515
381		831	3	1,486
381			3	1,486
STATE	TOTAL:		164,227	11,605,929

11/4/2011 06.29.03 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS
FOR THE MONTH: Oct-11

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	49,561	1,405,385
311		49,561	1,405,385
313	802	98,292	1,033,065
313		98,292	1,033,065
321	811	12,354	367,407
321		12,354	367,407
331	811	26	272,722
331	812	16	105,091
331		42	377,813
332	810	3,620	1,476,937
332	811	30	8,081
332		3,650	1,485,018
341	812	2	9,087
341		2	9,087
352	811	340	237,311
352		340	237,311
362	953	1	1,778
362		1	1,778
365	953	7	199,538
365		7	199,538
366	810	144	499,235
366		144	499,235
371	892	65	826,703

11/4/2011 06.29.03 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS
FOR THE MONTH: Oct-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	23	1,780,288
371			88	2,606,991
372		892	19	2,337,362
372		893	34	2,785,351
372			53	5,122,713
373		893	2	523,420
373			2	523,420
381		831	3	4,117
381			3	4,117
STATE	TOTAL:		164,539	13,872,878

12/6/2011 06.21.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
311		801	47,193	3,012,408
311			47,193	3,012,408
313		802	101,980	3,753,117
313			101,980	3,753,117
321		811	12,540	1,285,231
321			12,540	1,285,231
331		811	25	381,821
331		812	16	114,082
331			41	495,903
332		810	3,626	1,678,050
332		811	32	12,520
332			3,658	1,690,570
341		812	2	14,573
341			2	14,573
352		811	343	656,537
352			343	656,537
360		953	1	627,430
360			1	627,430
362		953	1	1,376
362			1	1,376
365		953	7	330,045
365			7	330,045
366		810	144	600,258

12/6/2011 06.21.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
366			144	600,258
371		892	65	1,066,557
371		893	23	1,886,300
371			88	2,952,857
372		892	19	2,690,907
372		893	34	3,353,888
372			53	6,044,795
373		893	2	642,319
373			2	642,319
381		831	3	8,177
381			3	8,177
STATE	TOTAL:		166,056	22,115,596

1/6/2012 06.28.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
311		801	47,445	5,454,082
311			47,445	5,454,082
313		802	103,106	7,766,226
313			103,106	7,766,226
321		811	12,712	3,199,872
321			12,712	3,199,872
331		811	25	560,561
331		812	16	194,286
331			41	754,847
332		810	3,647	2,053,756
332		811	36	23,008
332			3,683	2,076,764
341		812	2	20,311
341			2	20,311
352		811	345	1,390,122
352			345	1,390,122
360		953	1	3,152,700
360			1	3,152,700
362		953	1	1,085
362			1	1,085
365		953	7	68,461
365			7	68,461
366		810	144	755,322

1/6/2012 06.28.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-11

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
366			144	755,322
371		892	65	1,373,201
371		893	23	2,064,534
371			88	3,437,735
372		892	19	3,086,358
372		893	34	3,495,755
372			53	6,582,113
373		893	2	783,518
373			2	783,518
381		831	3	14,326
381			3	14,326
STATE	TOTAL:		167,633	35,457,484

2/4/2012 10.02.53 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	47,629	7,999,073
311		47,629	7,999,073
313	802	103,641	11,896,203
313		103,641	11,896,203
321	811	12,850	5,066,149
321		12,850	5,066,149
331	811	25	593,383
331	812	16	200,070
331		41	793,453
332	810	3,658	2,497,544
332	811	39	29,156
332		3,697	2,526,700
341	812	2	24,620
341		2	24,620
352	811	344	1,974,604
352		344	1,974,604
360	953	1	1,119,400
360		1	1,119,400
362	953	1	620
362		1	620
365	953	7	71,126
365		7	71,126
366	810	144	912,328

2/4/2012 10.02.53 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
366			144	912,328
371		892	65	1,426,181
371		893	22	680,207
371			87	2,106,388
372		892	19	3,214,553
372		893	35	5,336,202
372			54	8,550,755
373		893	2	789,537
373			2	789,537
381		831	3	16,473
381			3	16,473
STATE	TOTAL:		168,503	43,847,429

3/6/2012 06.18.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
311	801	47,749	6,944,595
311		47,749	6,944,595
313	802	103,839	10,275,099
313		103,839	10,275,099
321	811	12,880	4,372,713
321		12,880	4,372,713
328	951	1	10,186
328		1	10,186
331	811	25	519,755
331	812	16	259,223
331		41	778,978
332	810	3,655	2,249,443
332	811	42	27,684
332		3,697	2,277,127
341	812	2	20,899
341		2	20,899
352	811	344	1,674,696
352		344	1,674,696
360	953	1	335,200
360		1	335,200
362	953	1	514
362		1	514
365	953	7	16

3/6/2012 06.18.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365			7	16
366		810	144	832,402
366			144	832,402
371		892	65	1,277,302
371		893	22	636,391
371			87	1,913,693
372		892	19	3,034,985
372		893	35	4,873,943
372			54	7,908,928
373		893	2	678,382
373			2	678,382
381		831	3	13,760
381			3	13,760
STATE	TOTAL:		168,852	38,037,188

4/5/2012 06.08.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
221	802	3	372
221		3	372
301	801	118,472	9,904,267
301	802	33,248	2,993,111
301		151,720	12,897,378
302	810	1,013	524,350
302	811	15,533	4,441,997
302		16,546	4,966,347
311	801	45	19
311		45	19
313	801	6	563
313	802	85	-419
313		91	144
321	811	13	913
321		13	913
331	811	26	294,251
331	812	16	154,953
331		42	449,204
332	810	3	-31
332		3	-31
341	812	1	8,762
341		1	8,762
352	810	21	100,544
352	811	470	1,789,450

4/5/2012 06.08.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
352			491	1,889,994
362		953	2	2,723
362			2	2,723
365		953	7	144
365			7	144
371		892	64	874,534
371		893	22	542,111
371			86	1,416,645
372		892	19	2,684,098
372		893	33	4,086,828
372			52	6,770,926
373		893	2	511,483
373			2	511,483
381		831	3	4,964
381			3	4,964
STATE	TOTAL:		169,107	28,919,987

5/4/2012 06.07.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
221	802	3	-372
221		3	-372
301	801	150,910	4,013,835
301	802	12	624
301		150,922	4,014,459
302	811	16,423	2,334,846
302		16,423	2,334,846
311	801	10	2,575
311		10	2,575
313	802	33	3,486
313		33	3,486
321	811	5	3,662
321		5	3,662
331	811	25	229,939
331	812	16	124,191
331		41	354,130
332	810	2	40
332		2	40
341	812	1	10,806
341		1	10,806
352	811	491	949,721
352		491	949,721
362	953	2	1,600

5/4/2012 06.07.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
362			2	1,600
365		953	7	39,194
365			7	39,194
371		892	64	771,319
371		893	22	519,005
371			86	1,290,324
372		892	19	2,317,341
372		893	33	3,835,384
372			52	6,152,725
373		893	2	439,357
373			2	439,357
381		831	3	3,549
381			3	3,549
STATE	TOTAL:		168,083	15,600,102

6/6/2012 09.44.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	150,523	3,368,957
301	802	10	71
301		150,533	3,369,028
302	811	16,293	1,989,227
302		16,293	1,989,227
311	801	2	-374
311		2	-374
313	802	10	-173
313		10	-173
321	811	2	323
321		2	323
328	951	1	16,380
328		1	16,380
331	811	25	177,396
331	812	16	97,909
331		41	275,305
341	812	1	1,514
341		1	1,514
352	811	491	790,596
352		491	790,596
362	953	2	640
362		2	640
365	953	7	36,142

6/6/2012 09.44.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365			7	36,142
371		892	64	626,927
371		893	22	545,795
371			86	1,172,722
372		892	20	1,722,993
372		893	33	3,519,320
372			53	5,242,313
373		893	2	383,661
373			2	383,661
381		831	3	2,032
381			3	2,032
STATE	TOTAL:		167,527	13,279,336

7/6/2012 06.42.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	149,717	2,068,481
301	802	11	46
301		149,728	2,068,527
302	810	2	769
302	811	16,154	1,733,427
302		16,156	1,734,196
311	801	1	86
311		1	86
313	801	1	65
313	802	8	1,776
313		9	1,841
321	811	2	863
321		2	863
328	951	1	170,554
328		1	170,554
331	811	27	156,898
331	812	13	31,319
331		40	188,217
332	810	1	423
332		1	423
341	812	1	
341		1	
352	811	496	615,395
352		496	615,395

7/6/2012 06.42.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
362	953	2	450
362		2	450
365	953	8	1,507
365		8	1,507
371	892	64	709,345
371	893	24	546,727
371		88	1,256,072
372	892	19	2,015,362
372	893	33	3,369,510
372		52	5,384,872
373	893	2	372,947
373		2	372,947
381	831	3	1,583
381		3	1,583
STATE	TOTAL:	166,590	11,797,533

8/4/2012 11.27.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	149,423	1,648,432
301	802	13	48
301		149,436	1,648,480
302	810	3	1,150
302	811	16,097	1,525,563
302		16,100	1,526,713
311	801	1	2
311		1	2
313	802	1	239
313		1	239
321	811	3	3,553
321		3	3,553
331	811	27	150,163
331	812	13	31,684
331		40	181,847
341	812	2	3,645
341		2	3,645
352	811	496	488,102
352		496	488,102
360	953	1	388,000
360		1	388,000
362	953	2	598
362		2	598

8/4/2012 11.27.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365		953	8	45,246
365			8	45,246
371		892	64	491,805
371		893	24	539,676
371			88	1,031,481
372		892	19	1,831,229
372		893	33	3,386,762
372			52	5,217,991
373		893	2	334,547
373			2	334,547
381		831	3	1,438
381			3	1,438
STATE	TOTAL:		166,235	10,871,882

9/7/2012 08.28.44 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	149,351	1,485,730
301	802	14	42
301		149,365	1,485,772
302	810	4	1,420
302	811	16,048	1,490,080
302		16,052	1,491,500
311	801	4	146
311		4	146
313	802	3	254
313		3	254
321	811	1	-17
321		1	-17
328	951	1	
328		1	
331	811	27	178,012
331	812	13	31,591
331		40	209,603
341	812	2	6,088
341		2	6,088
352	811	495	532,113
352		495	532,113
360	953	1	62,000
360		1	62,000

9/7/2012 08.28.44 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
362		953	2	560
362			2	560
365		953	8	1,181
365			8	1,181
371		892	64	518,292
371		893	24	555,303
371			88	1,073,595
372		892	19	1,729,729
372		893	33	3,478,634
372			52	5,208,363
373		893	2	379,548
373			2	379,548
381		831	3	1,692
381			3	1,692
STATE	TOTAL:		166,119	10,452,398

10/4/2012 05.49.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	149,285	1,757,535
301	802	19	199
301		149,304	1,757,734
302	810	4	1,689
302	811	15,972	1,633,227
302		15,976	1,634,916
311	801	5	411
311		5	411
313	802	7	1,396
313		7	1,396
321	811	3	460
321		3	460
331	811	27	180,218
331	812	13	34,101
331		40	214,319
341	812	2	2,749
341		2	2,749
352	811	498	517,655
352		498	517,655
360	953	1	552,000
360		1	552,000
362	953	1	1,595
362		1	1,595

10/4/2012 05.49.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365		953	8	54,106
365			8	54,106
371		892	64	585,347
371		893	23	537,477
371			87	1,122,824
372		892	19	1,886,492
372		893	33	3,376,668
372			52	5,263,160
373		893	2	350,766
373			2	350,766
381		831	3	1,898
381			3	1,898
STATE	TOTAL:		165,989	11,475,989

11/6/2012 06.16.24 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	149,758	2,407,889
301	802	23	192
301		149,781	2,408,081
302	810	4	2,458
302	811	16,009	1,748,026
302		16,013	1,750,484
311	801	2	595
311		2	595
313	802	2	678
313		2	678
321	811	1	-541
321		1	-541
331	811	27	265,918
331	812	13	66,393
331		40	332,311
341	812	2	17,683
341		2	17,683
352	811	496	677,970
352		496	677,970
362	953	1	2,158
362		1	2,158
365	953	8	102,977
365		8	102,977

11/6/2012 06.16.24 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	64	880,662
371		893	23	696,385
371			87	1,577,047
372		892	19	2,199,949
372		893	33	4,445,488
372			52	6,645,437
373		893	2	461,948
373			2	461,948
381		831	3	5,575
381			3	5,575
STATE	TOTAL:		166,490	13,982,403

12/6/2012 04.46.39 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	151,164	8,932,648
301	802	26	1,522
301		151,190	8,934,170
302	810	5	4,350
302	811	16,237	3,839,016
302		16,242	3,843,366
311	801	1	78
311		1	78
313	801	1	
313	802	2	241
313		3	241
321	811	3	496
321		3	496
331	811	27	440,670
331	812	14	135,519
331		41	576,189
332	810	1	371
332		1	371
341	812	2	24,754
341		2	24,754
352	811	495	1,612,449
352		495	1,612,449
362	953	1	2,075
362		1	2,075

12/6/2012 04.46.39 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365		953	9	87,806
365			9	87,806
371		892	66	1,185,706
371		893	23	805,668
371			89	1,991,374
372		892	19	2,615,927
372		893	32	4,994,314
372			51	7,610,241
373		893	2	602,424
373			2	602,424
381		831	3	12,549
381			3	12,549
STATE	TOTAL:		168,133	25,298,583

1/5/2013 04.46.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-12

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,336	12,876,295
301	802	30	2,003
301		152,366	12,878,298
302	810	4	7,296
302	811	16,444	5,036,303
302		16,448	5,043,599
311	801	1	81
311		1	81
313	802	1	128
313		1	128
331	811	27	507,603
331	812	14	167,909
331		41	675,512
341	812	2	27,341
341		2	27,341
352	811	496	1,939,629
352		496	1,939,629
362	953	1	1,947
362		1	1,947
365	953	9	116,453
365		9	116,453
371	892	65	1,285,147
371	893	23	729,069
371		88	2,014,216

1/5/2013 04.46.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-12

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	3,135,534
372		893	32	5,078,201
372			51	8,213,735
373		893	2	598,644
373			2	598,644
381		831	3	16,745
381			3	16,745
STATE	TOTAL:		169,509	31,526,328

2/6/2013 04.47.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,982	20,641,749
301	802	33	3,897
301		153,015	20,645,646
302	810	4	8,737
302	811	16,635	8,252,872
302		16,639	8,261,609
311	801	1	185
311		1	185
313	802	5	720
313		5	720
331	811	27	639,282
331	812	14	220,147
331		41	859,429
341	812	2	33,629
341		2	33,629
352	811	495	2,984,825
352		495	2,984,825
362	953	1	1,079
362		1	1,079
365	953	9	34,315
365		9	34,315
371	892	65	1,526,142
371	893	23	835,631
371		88	2,361,773

2/6/2013 04.47.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	3,520,537
372		893	32	5,704,787
372			51	9,225,324
373		893	2	708,912
373			2	708,912
381		831	3	22,922
381			3	22,922
STATE	TOTAL:		170,352	45,140,368

3/6/2013 04.48.09 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,157	21,053,493
301	802	34	3,451
301		153,191	21,056,944
302	810	4	9,480
302	811	16,678	8,023,996
302		16,682	8,033,476
311	801	2	14
311		2	14
313	802	2	22
313		2	22
331	811	27	557,839
331	812	14	203,110
331		41	760,949
341	812	2	26,956
341		2	26,956
352	811	501	2,785,581
352		501	2,785,581
362	953	1	1,073
362		1	1,073
365	953	9	107,325
365		9	107,325
371	892	65	1,329,064
371	893	23	735,427
371		88	2,064,491

3/6/2013 04.48.09 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	3,069,409
372		893	32	5,211,762
372			51	8,281,171
373		893	2	634,015
373			2	634,015
381		831	3	19,713
381			3	19,713
STATE	TOTAL:		170,575	43,771,730

4/4/2013 04.48.59 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	153,385	18,641,130
301		802	36	3,086
301			153,421	18,644,216
302		810	4	9,416
302		811	16,691	7,242,197
302			16,695	7,251,613
311		801	3	569
311			3	569
313		802	3	179
313			3	179
331		811	27	574,040
331		812	14	208,971
331			41	783,011
341		812	2	27,750
341			2	27,750
352		811	498	2,638,210
352			498	2,638,210
360		953	1	1,794,330
360			1	1,794,330
362		953	1	
362			1	
365		953	9	56,187
365			9	56,187

4/4/2013 04.48.59 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	65	1,410,318
371		893	23	804,857
371			88	2,215,175
372		892	19	3,114,257
372		893	32	5,443,727
372			51	8,557,984
373		893	2	694,012
373			2	694,012
381		831	3	19,621
381			3	19,621
STATE	TOTAL:		170,818	42,682,857

5/4/2013 04.48.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,481	13,471,896
301	802	35	2,206
301		153,516	13,474,102
302	810	4	7,353
302	811	16,670	5,274,870
302		16,674	5,282,223
311	801	1	175
311		1	175
313	802	2	58
313		2	58
321	811	1	-349
321		1	-349
331	811	27	296,408
331	812	14	84,664
331		41	381,072
341	812	2	20,123
341		2	20,123
352	811	494	1,885,042
352		494	1,885,042
360	953	1	7,242,470
360		1	7,242,470
362	953	1	
362		1	

5/4/2013 04.48.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365		953	9	30,854
365			9	30,854
371		892	65	882,008
371		893	23	693,169
371			88	1,575,177
372		892	19	2,477,537
372		893	32	4,602,773
372			51	7,080,310
373		893	2	519,394
373			2	519,394
381		831	3	6,320
381			3	6,320
STATE	TOTAL:		170,886	37,496,971

6/6/2013 04.48.58 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,163	4,999,387
301	802	35	612
301		153,198	4,999,999
302	810	4	3,974
302	811	16,559	2,623,834
302		16,563	2,627,808
311	801	1	7
311		1	7
321	811	1	9
321		1	9
331	811	27	199,570
331	812	14	49,311
331		41	248,881
341	812	2	14,415
341		2	14,415
352	811	492	974,473
352		492	974,473
360	953	1	791,000
360		1	791,000
362	953	1	
362		1	
365	953	9	28,409
365		9	28,409

6/6/2013 04.48.58 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	65	699,705
371		893	23	639,422
371			88	1,339,127
372		892	19	2,131,320
372		893	32	4,061,218
372			51	6,192,538
373		893	2	440,631
373			2	440,631
381		831	3	3,350
381			3	3,350
STATE	TOTAL:		170,453	17,660,647

7/4/2013 05.22.22 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,624	2,606,423
301	802	35	196
301		152,659	2,606,619
302	811	16,473	1,921,813
302		16,473	1,921,813
313	802	1	
313		1	
331	811	27	177,760
331	812	17	59,954
331		44	237,714
341	812	2	
341		2	
352	811	431	602,494
352		431	602,494
360	953	1	2,370,000
360		1	2,370,000
365	953	8	44,608
365		8	44,608
371	892	61	544,297
371	893	23	564,382
371		84	1,108,679
372	892	19	1,803,185
372	893	32	3,517,960
372		51	5,321,145

7/4/2013 05.22.22 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	399,427
373			1	399,427
381		831	3	2,081
381			3	2,081
STATE	TOTAL:		169,758	14,614,580

8/6/2013 11.46.09 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,542	1,725,424
301	802	34	177
301		152,576	1,725,601
302	811	16,421	1,606,588
302		16,421	1,606,588
311	801	3	10
311		3	10
313	802	2	1
313		2	1
331	811	27	162,918
331	812	17	71,722
331		44	234,640
341	812	2	
341		2	
352	811	428	460,847
352		428	460,847
365	953	8	185,715
365		8	185,715
371	892	61	549,102
371	893	23	543,698
371		84	1,092,800
372	892	19	2,017,814
372	893	32	3,477,261
372		51	5,495,075

8/6/2013 11.46.09 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	357,500
373			1	357,500
381		831	3	1,991
381			3	1,991
STATE	TOTAL:		169,623	11,160,768

9/6/2013 04.47.11 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,359	1,786,679
301	802	35	100
301		152,394	1,786,779
302	811	16,337	1,703,672
302		16,337	1,703,672
331	811	27	182,983
331	812	17	74,296
331		44	257,279
341	812	2	2,666
341		2	2,666
352	811	428	526,461
352		428	526,461
360	953	1	4,025,000
360		1	4,025,000
365	953	8	3,314
365		8	3,314
371	892	61	535,870
371	893	23	573,099
371		84	1,108,969
372	892	19	1,982,262
372	893	32	3,635,172
372		51	5,617,434
373	893	1	407,686
373		1	407,686

9/6/2013 04.47.11 PIEDMONT NATURAL GAS STATE: TN ZCSRP620-B

TOTAL BILL COUNT AND THERMS BY RATE/CLASS

FOR THE MONTH: Aug-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	2,241
381			3	2,241
STATE	TOTAL:		169,353	15,441,501

10/4/2013 04.46.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	152,213	1,770,919
301	802	34	88
301		152,247	1,771,007
302	811	16,272	1,661,355
302		16,272	1,661,355
311	801	1	2
311		1	2
331	811	27	194,714
331	812	17	80,410
331		44	275,124
341	812	3	21,096
341		3	21,096
352	811	427	512,644
352		427	512,644
360	953	1	2,970,000
360		1	2,970,000
365	953	8	63,069
365		8	63,069
371	892	61	593,983
371	893	23	541,787
371		84	1,135,770
372	892	19	2,036,944
372	893	32	3,754,463
372		51	5,791,407

10/4/2013 04.46.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	419,684
373			1	419,684
381		831	3	2,629
381			3	2,629
STATE	TOTAL:		169,142	14,623,787

11/6/2013 04.47.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	152,451	2,255,193
301		802	35	221
301			152,486	2,255,414
302		811	16,275	1,962,743
302			16,275	1,962,743
311		801	3	18
311			3	18
313		802	2	
313			2	
331		811	27	289,574
331		812	18	143,091
331			45	432,665
341		812	2	31,142
341			2	31,142
352		811	424	635,783
352			424	635,783
360		953	1	4,594,000
360			1	4,594,000
365		953	8	68,181
365			8	68,181
371		892	61	839,520
371		893	23	704,638
371			84	1,544,158

11/6/2013 04.47.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	2,270,586
372		893	32	4,381,329
372			51	6,651,915
373		893	1	515,947
373			1	515,947
381		831	3	6,012
381			3	6,012
STATE	TOTAL:		169,385	18,697,978

12/5/2013 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,761	8,528,043
301	802	35	1,490
301		153,796	8,529,533
302	811	16,500	3,813,721
302		16,500	3,813,721
311	801	4	162
311		4	162
313	802	4	113
313		4	113
321	811	1	14
321		1	14
331	811	27	511,115
331	812	18	242,837
331		45	753,952
341	812	2	31,629
341		2	31,629
352	811	424	1,364,451
352		424	1,364,451
365	953	8	244,665
365		8	244,665
371	892	61	1,259,123
371	893	23	834,942
371		84	2,094,065

12/5/2013 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	2,604,036
372		893	32	5,232,250
372			51	7,836,286
373		893	1	649,205
373			1	649,205
381		831	3	19,870
381			3	19,870
STATE	TOTAL:		170,923	25,337,666

1/7/2014 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-13

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	155,007	18,527,881
301	802	35	3,474
301		155,042	18,531,355
302	811	16,729	7,554,845
302		16,729	7,554,845
311	801	4	441
311		4	441
313	802	4	261
313		4	261
321	811	1	96
321		1	96
331	811	28	633,193
331	812	18	314,738
331		46	947,931
341	812	2	41,106
341		2	41,106
342	815	1	1,013
342		1	1,013
352	811	425	2,472,921
352		425	2,472,921
360	953	1	1,585,260
360		1	1,585,260
365	953	8	291,930

1/7/2014 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-13

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365			8	291,930
371		892	61	1,498,888
371		893	23	911,977
371			84	2,410,865
372		892	19	3,008,377
372		893	32	5,746,824
372			51	8,755,201
373		893	1	764,491
373			1	764,491
381		831	3	27,630
381			3	27,630
STATE	TOTAL:		172,402	43,385,346

2/6/2014 04.49.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	155,740	27,981,712
301	802	36	5,238
301		155,776	27,986,950
302	811	16,903	11,810,070
302		16,903	11,810,070
311	801	4	-620
311		4	-620
313	802	5	-259
313		5	-259
321	811	1	-110
321		1	-110
331	811	27	859,746
331	812	18	424,452
331		45	1,284,198
341	812	2	38,796
341		2	38,796
342	815	1	
342		1	
352	811	423	3,603,556
352		423	3,603,556
361	811	17	137,391
361	812	34	320,645
361		51	458,036

2/6/2014 04.49.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
365		953	9	135,739
365			9	135,739
371		892	61	1,883,780
371		893	23	1,068,781
371			84	2,952,561
372		892	19	2,830,857
372		893	32	5,887,793
372			51	8,718,650
373		893	1	830,826
373			1	830,826
381		831	3	43,638
381			3	43,638
STATE	TOTAL:		173,359	57,862,031

3/6/2014 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,033	31,317,922
301	802	37	5,423
301		156,070	31,323,345
302	811	16,995	12,487,904
302		16,995	12,487,904
328	951	2	26,000
328	952	1	13,913
328		3	39,913
331	811	27	667,439
331	812	18	336,383
331		45	1,003,822
341	812	2	31,609
341		2	31,609
342	815	1	24,968
342		1	24,968
352	811	427	3,637,196
352		427	3,637,196
360	953	1	801,000
360		1	801,000
365	953	9	111,942
365		9	111,942
371	892	61	1,529,727
371	893	23	947,496
371		84	2,477,223

3/6/2014 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	2,770,925
372		893	32	5,599,775
372			51	8,370,700
373		893	1	756,011
373			1	756,011
381		831	3	29,798
381			3	29,798
STATE	TOTAL:		173,692	61,095,431

4/4/2014 12.05.15 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,423	20,063,359
301	802	37	3,475
301		156,460	20,066,834
302	811	17,024	8,303,869
302		17,024	8,303,869
313	802	1	-335
313		1	-335
331	811	27	565,963
331	812	18	278,330
331		45	844,293
341	812	2	33,413
341		2	33,413
342	815	1	35,347
342		1	35,347
352	811	431	2,543,767
352		431	2,543,767
365	953	9	9,336
365		9	9,336
371	892	58	1,254,120
371	893	23	902,060
371		81	2,156,180
372	892	20	2,280,084
372	893	32	5,658,563
372		52	7,938,647

4/4/2014 12.05.15 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	736,003
373			1	736,003
381		831	3	22,487
381			3	22,487
STATE	TOTAL:		174,110	42,689,841

5/6/2014 04.48.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	155,812	11,438,705
301	802	37	1,909
301		155,849	11,440,614
302	811	16,961	4,898,764
302		16,961	4,898,764
331	811	27	260,747
331	812	18	168,744
331		45	429,491
341	812	2	21,568
341		2	21,568
342	815	1	41,367
342		1	41,367
352	811	427	1,571,835
352		427	1,571,835
360	953	1	1,600,000
360		1	1,600,000
365	953	9	3,953
365		9	3,953
371	892	59	865,617
371	893	23	641,220
371		82	1,506,837
372	892	20	2,401,808
372	893	32	4,247,863
372		52	6,649,671

5/6/2014 04.48.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	476,306
373			1	476,306
381		831	3	7,462
381			3	7,462
STATE	TOTAL:		173,433	28,647,868

6/6/2014 09.46.58 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	155,271	4,188,988
301	802	37	405
301		155,308	4,189,393
302	811	16,822	2,573,926
302		16,822	2,573,926
331	811	28	188,639
331	812	18	142,492
331		46	331,131
341	812	2	5,429
341		2	5,429
342	815	1	44,184
342		1	44,184
352	811	428	843,170
352		428	843,170
365	953	9	116,709
365		9	116,709
371	892	59	653,129
371	893	23	619,132
371		82	1,272,261
372	892	20	1,681,589
372	893	32	3,955,614
372		52	5,637,203
373	893	1	433,170
373		1	433,170

6/6/2014 09.46.58 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	4,109
381			3	4,109
STATE	TOTAL:		172,754	15,450,685

7/4/2014 04.47.53 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	154,517	2,430,568
301	802	37	143
301		154,554	2,430,711
302	811	16,796	1,956,588
302		16,796	1,956,588
331	811	24	147,287
331	812	17	126,520
331		41	273,807
341	812	2	22,292
341		2	22,292
342	815	2	58,149
342		2	58,149
352	811	354	591,242
352		354	591,242
365	953	9	116,267
365		9	116,267
371	892	55	530,782
371	893	22	565,566
371		77	1,096,348
372	892	20	1,777,635
372	893	32	3,576,668
372		52	5,354,303
373	893	1	414,992
373		1	414,992

7/4/2014 04.47.53 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	2,825
381			3	2,825
STATE	TOTAL:		171,891	12,317,524

8/6/2014 05.07.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	154,272	1,868,508
301	802	37	111
301		154,309	1,868,619
302	811	16,733	1,858,978
302		16,733	1,858,978
311	801	1	-172
311		1	-172
331	811	25	156,354
331	812	17	131,764
331		42	288,118
341	812	2	20,696
341		2	20,696
342	815	3	83,885
342		3	83,885
352	811	354	520,714
352		354	520,714
365	953	9	40,719
365		9	40,719
371	892	54	540,251
371	893	22	577,014
371		76	1,117,265
372	892	20	2,134,093
372	893	32	3,720,893
372		52	5,854,986

8/6/2014 05.07.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	357,352
373			1	357,352
381		831	3	1,302
381			3	1,302
STATE	TOTAL:		171,585	12,012,462

9/5/2014 04.48.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,832	1,797,608
301	802	38	253
301		153,870	1,797,861
302	811	16,605	1,731,995
302		16,605	1,731,995
331	811	24	153,997
331	812	17	126,446
331		41	280,443
341	812	2	18,476
341		2	18,476
342	815	3	98,021
342		3	98,021
352	811	354	500,245
352		354	500,245
365	953	9	15,539
365		9	15,539
371	892	54	519,422
371	893	22	585,867
371		76	1,105,289
372	892	20	2,181,037
372	893	32	3,793,243
372		52	5,974,280
373	893	1	418,445
373		1	418,445

9/5/2014 04.48.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
381		831	3
381			3
STATE	TOTAL:	171,016	11,940,594

10/4/2014 04.48.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,791	1,796,447
301	802	39	479
301		153,830	1,796,926
302	811	16,551	1,756,489
302		16,551	1,756,489
331	811	24	161,739
331	812	17	131,719
331		41	293,458
341	812	2	10,204
341		2	10,204
342	815	3	90,606
342		3	90,606
352	811	352	523,060
352		352	523,060
365	953	8	62,260
365		8	62,260
371	892	54	568,007
371	893	22	597,479
371		76	1,165,486
372	892	20	2,291,258
372	893	32	3,847,396
372		52	6,138,654
373	893	1	395,815
373		1	395,815

10/4/2014 04.48.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
381		831	3
381			3
STATE	TOTAL:	170,919	12,232,958

11/6/2014 04.49.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	153,798	2,406,524
301	802	39	628
301		153,837	2,407,152
302	811	16,544	2,116,972
302		16,544	2,116,972
331	811	24	186,641
331	812	17	163,032
331		41	349,673
341	812	2	20,723
341		2	20,723
342	815	3	86,910
342		3	86,910
352	811	349	669,128
352		349	669,128
360	953	1	50,000
360		1	50,000
365	953	8	84,261
365		8	84,261
371	892	54	1,498,308
371	893	22	1,372,506
371		76	2,870,814
372	892	20	4,657,684
372	893	32	8,510,372
372		52	13,168,056

11/6/2014 04.49.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	1,059,396
373			1	1,059,396
381		831	3	
381			3	
STATE	TOTAL:		170,917	22,883,085

12/5/2014 04.49.16 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	154,925	9,076,000
301	802	39	2,222
301		154,964	9,078,222
302	811	16,716	4,385,534
302		16,716	4,385,534
331	811	24	422,616
331	812	17	281,360
331		41	703,976
341	812	2	31,687
341		2	31,687
342	815	3	96,505
342		3	96,505
352	811	352	1,472,839
352		352	1,472,839
365	953	7	384,068
365		7	384,068
371	892	54	490,007
371	893	22	145,709
371		76	635,716
372	892	20	858,448
372	893	32	1,208,777
372		52	2,067,225
373	893	1	143,716
373		1	143,716

12/5/2014 04.49.16 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
381		831	2
381			2
STATE	TOTAL:	172,216	18,999,488

1/8/2015 04.48.35 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-14

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,888	17,945,020
301	802	40	4,007
301		156,928	17,949,027
302	810	1	2,360
302	811	17,071	7,919,040
302		17,072	7,921,400
313	802	1	
313		1	
331	811	24	512,635
331	812	17	318,987
331		41	831,622
341	812	2	34,323
341		2	34,323
342	815	3	89,252
342		3	89,252
352	811	351	2,278,822
352		351	2,278,822
360	953	1	3,139,990
360		1	3,139,990
365	953	7	325,817
365		7	325,817
371	892	54	1,349,761
371	893	22	883,666
371		76	2,233,427

1/8/2015 04.48.35 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-14

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	20	3,664,755
372		893	32	5,655,908
372			52	9,320,663
373		893	1	687,251
373			1	687,251
381		831	2	
381			2	
STATE	TOTAL:		174,537	44,811,594

2/5/2015 04.48.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	157,576	25,617,470
301	802	39	5,525
301		157,615	25,622,995
302	810	1	6,816
302	811	17,168	10,795,019
302		17,169	10,801,835
331	811	24	698,299
331	812	17	404,512
331		41	1,102,811
341	812	2	31,615
341		2	31,615
342	815	3	104,991
342		3	104,991
352	811	355	2,992,015
352		355	2,992,015
361	811	20	528,289
361	812	34	
361		54	528,289
365	953	7	-15,699
365		7	-15,699
371	892	53	1,528,435
371	893	22	988,182
371		75	2,516,617
372	892	20	3,803,761

2/5/2015 04.48.02 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		893	31	5,822,926
372			51	9,626,687
373		893	1	756,802
373			1	756,802
381		831	2	
381			2	
STATE	TOTAL:		175,375	54,068,958

3/6/2015 04.56.41 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	157,897	25,701,334
301	802	39	5,872
301		157,936	25,707,206
302	810	1	5,026
302	811	17,207	11,240,555
302		17,208	11,245,581
328	952	1	17,536
328		1	17,536
331	811	24	688,824
331	812	17	416,675
331		41	1,105,499
341	812	2	37,863
341		2	37,863
342	815	3	99,038
342		3	99,038
352	811	350	2,941,984
352		350	2,941,984
361	811	1	-528,289
361	812	2	
361	892	19	
361	893	32	
361		54	-528,289
365	953	7	97,474
365		7	97,474

3/6/2015 04.56.41 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	53	1,532,063
371		893	23	995,650
371			76	2,527,713
372		892	20	3,698,132
372		893	31	5,391,034
372			51	9,089,166
373		893	1	614,930
373			1	614,930
381		831	2	
381			2	
STATE	TOTAL:		175,732	52,955,701

4/04/15 06.33.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	158,340	26,051,997
301	802	39	5,217
301		158,379	26,057,214
302	810	1	4,781
302	811	17,226	10,643,240
302	818	1	3,045
302		17,228	10,651,066
328	951	1	21,392
328		1	21,392
331	809	2	101,241
331	811	24	423,605
331	812	17	277,711
331		43	802,557
341	812	2	25,289
341		2	25,289
352	811	351	2,717,177
352		351	2,717,177
365	953	7	26,583
365		7	26,583
371	892	53	1,114,284
371	893	23	862,475
371	897	1	31,313
371		77	2,008,072
372	892	20	3,460,328
372	893	31	5,351,000

4/04/15 06.33.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			51	8,811,328
373		893	1	634,717
373			1	634,717
381		831	2	
381			2	
STATE	TOTAL:		176,142	51,755,395

5/06/15 05.01.31 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	158,016	9,156,234
301	802	39	2,048
301		158,055	9,158,282
302	810	1	3,134
302	811	17,183	4,454,889
302	818	1	4,448
302		17,185	4,462,471
331	809	2	136,876
331	811	24	213,655
331	812	17	173,096
331		43	523,627
341	812	2	13,637
341		2	13,637
342	815	3	-32,990
342		3	-32,990
352	811	349	1,320,938
352		349	1,320,938
360	953	1	96,000
360		1	96,000
365	953	7	130,408
365		7	130,408
371	892	53	711,906
371	893	23	671,528
371	897	1	-7,429
371		77	1,376,005

5/06/15 05.01.31 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
372	892	20	2,883,928
372	893	31	4,365,392
372		51	7,249,320
373	893	1	480,118
373		1	480,118
381	831	2	
381		2	
STATE TOTAL:		175,776	24,777,816

6/04/15 04.48.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	157,266	3,598,084
301	802	39	659
301		157,305	3,598,743
302	810	1	765
302	811	17,059	2,454,583
302	818	1	5,845
302		17,061	2,461,193
331	809	1	76,341
331	811	24	171,929
331	812	17	153,399
331		42	401,669
341	812	2	3,534
341		2	3,534
352	811	351	655,376
352		351	655,376
360	953	1	896,000
360		1	896,000
365	953	7	61,481
365		7	61,481
371	892	53	573,473
371	893	23	601,255
371	897	1	8,152
371		77	1,182,880
372	892	20	2,835,695
372	893	31	3,697,929

6/04/15 04.48.10 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			51	6,533,624
373		893	1	425,357
373			1	425,357
381		831	2	
381			2	
STATE	TOTAL:		174,900	16,219,857

7/07/15 04.54.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,838	2,339,387
301	802	39	652
301		156,877	2,340,039
302	810	1	11
302	811	16,959	1,947,728
302	818	1	6,199
302		16,961	1,953,938
331	809	1	83,635
331	811	25	171,895
331	812	17	129,916
331		43	385,446
341	812	2	5,132
341		2	5,132
352	811	352	564,364
352		352	564,364
365	953	7	53,431
365		7	53,431
371	892	54	505,325
371	893	23	604,544
371	897	1	5,618
371		78	1,115,487
372	892	20	2,907,513
372	893	31	3,560,570
372		51	6,468,083
373	893	1	410,089

7/07/15 04.54.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	410,089
381		831	2	
381			2	
STATE	TOTAL:		174,374	13,296,009

8/06/15 04.48.55 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,504	2,003,687
301	802	39	697
301		156,543	2,004,384
302	810	1	11
302	811	16,877	1,940,865
302	818	1	8,705
302		16,879	1,949,581
331	809	1	95,299
331	811	25	163,576
331	812	17	128,848
331		43	387,723
341	812	2	641
341		2	641
352	811	350	521,087
352		350	521,087
365	953	7	54,891
365		7	54,891
371	892	54	488,239
371	893	23	590,030
371	897	1	5,475
371		78	1,083,744
372	892	20	3,073,571
372	893	31	3,573,204
372		51	6,646,775
373	893	1	366,139

8/06/15 04.48.55 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	366,139
381		831	2	
381			2	
STATE	TOTAL:		173,956	13,014,965

9/04/15 04.47.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,044	1,731,573
301	802	38	588
301		156,082	1,732,161
302	810	1	10
302	811	16,818	1,789,763
302	818	1	6,190
302		16,820	1,795,963
331	809	1	102,000
331	811	25	170,664
331	812	17	129,743
331		43	402,407
341	812	2	17,849
341		2	17,849
352	811	345	460,297
352		345	460,297
365	953	7	62,046
365		7	62,046
371	892	54	520,050
371	893	23	612,373
371	897	1	4,761
371		78	1,137,184
372	892	20	3,201,063
372	893	31	3,695,668
372		51	6,896,731
373	893	1	436,449

9/04/15 04.47.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	436,449
381		831	2	
381			2	
STATE	TOTAL:		173,431	12,941,087

10/06/15 05.50.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,122	1,875,207
301	802	39	593
301		156,161	1,875,800
302	810	1	9
302	811	16,779	1,778,267
302	818	1	6,825
302		16,781	1,785,101
328	951	1	92,680
328		1	92,680
331	809	1	108,842
331	811	26	153,028
331	812	17	128,194
331		44	390,064
341	812	2	16,145
341		2	16,145
352	811	342	513,008
352		342	513,008
365	953	7	59,801
365		7	59,801
371	892	54	631,917
371	893	23	610,658
371	897	1	5,123
371		78	1,247,698
372	892	20	3,115,725
372	893	31	3,638,295

10/06/15 05.50.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			51	6,754,020
373		893	1	416,449
373			1	416,449
381		831	2	
381			2	
STATE	TOTAL:		173,470	13,150,766

11/05/15 04.55.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	156,431	2,636,256
301	802	38	771
301		156,469	2,637,027
302	810	1	11
302	811	16,771	2,214,222
302	818	1	4,079
302		16,773	2,218,312
331	809	1	111,424
331	811	26	203,022
331	812	17	164,441
331		44	478,887
341	812	2	22,371
341		2	22,371
352	811	343	651,665
352		343	651,665
365	953	7	47,428
365		7	47,428
371	892	54	732,693
371	893	23	674,621
371	897	1	4,494
371		78	1,411,808
372	892	20	3,158,072
372	893	31	4,029,279
372		51	7,187,351
373	893	1	509,073

11/05/15 04.55.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	509,073
381		831	2	21
381			2	21
STATE	TOTAL:		173,770	15,163,943

12/04/15 04.56.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	157,473	4,940,964
301	802	39	1,080
301		157,512	4,942,044
302	810	1	530
302	811	16,887	2,902,496
302	818	1	3,215
302		16,889	2,906,241
311	801	1	35
311		1	35
331	809	1	104,156
331	811	27	327,132
331	812	17	196,013
331		45	627,301
341	812	2	14,471
341		2	14,471
352	811	343	906,525
352		343	906,525
360	953	1	460,000
360		1	460,000
365	953	7	1,733
365		7	1,733
371	892	54	903,006
371	893	24	779,814
371	897	1	4,316
371		79	1,687,136

12/04/15 04.56.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-15

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	20	3,382,577
372		893	31	4,341,566
372			51	7,724,143
373		893	1	623,774
373			1	623,774
381		831	2	
381			2	
STATE	TOTAL:		174,933	19,893,403

1/07/16 04.56.27 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,121	11,163,366
301	802	40	2,455
301		159,161	11,165,821
302	810	1	2,740
302	811	17,159	5,019,999
302	818	1	3,286
302		17,161	5,026,025
311	801	1	98
311		1	98
331	809	1	113,378
331	811	26	387,118
331	812	17	241,043
331		44	741,539
341	812	2	19,722
341		2	19,722
352	811	345	1,468,378
352		345	1,468,378
360	953	1	720,000
360		1	720,000
365	953	7	250,539
365		7	250,539
371	892	54	1,052,710
371	893	24	770,327
371	897	1	7,481
371		79	1,830,518

1/07/16 04.56.27 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-15

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
372	892	20	3,856,046
372	893	31	4,857,706
372		51	8,713,752
373	893	1	718,481
373		1	718,481
381	831	2	
381		2	
STATE TOTAL:		176,855	30,654,873

2/04/16 04.55.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,977	18,489,431
301	802	40	4,027
301		160,017	18,493,458
302	810	1	885
302	811	17,300	8,642,552
302	818	1	2,460
302		17,302	8,645,897
311	801	1	144
311		1	144
331	809	1	104,922
331	811	26	649,820
331	812	17	406,959
331		44	1,161,701
341	812	2	28,388
341		2	28,388
352	811	345	2,294,273
352		345	2,294,273
365	953	7	9,308
365		7	9,308
371	892	55	1,573,392
371	893	24	1,105,195
371	897	1	4,700
371		80	2,683,287
372	892	19	4,738,253
372	893	31	5,999,241

2/04/16 04.55.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			50	10,737,494
373		893	1	884,705
373			1	884,705
381		831	2	
381			2	
STATE	TOTAL:		177,851	44,938,655

3/04/16 04.55.36 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	160,524	23,216,606
301	802	40	4,946
301		160,564	23,221,552
302	810	1	346
302	811	17,381	10,077,978
302	818	1	1,834
302		17,383	10,080,158
311	801	1	184
311		1	184
331	809	1	111,154
331	811	26	534,959
331	812	17	324,427
331		44	970,540
341	812	2	19,386
341		2	19,386
352	811	345	2,452,795
352		345	2,452,795
360	953	1	100,000
360		1	100,000
362	953	1	24,872
362		1	24,872
365	953	7	134,483
365		7	134,483
371	892	55	1,269,477

3/04/16 04.55.36 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
371	893	24	978,746
371	897	1	5,735
371		80	2,253,958
372	892	18	4,038,755
372	893	31	5,380,994
372		49	9,419,749
373	893	1	785,354
373		1	785,354
381	831	2	
381		2	
STATE	TOTAL:	178,480	49,463,031

4/06/16 04.49.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	160,882	16,281,503
301	802	39	3,280
301		160,921	16,284,783
302	810	1	2,554
302	811	17,398	7,444,139
302	818	1	2,497
302		17,400	7,449,190
311	801	1	159
311		1	159
331	809	1	123,498
331	811	26	307,492
331	812	17	216,523
331		44	647,513
341	812	2	12,064
341		2	12,064
352	811	348	1,861,459
352		348	1,861,459
360	953	1	202,200
360		1	202,200
365	953	4	194,406
365		4	194,406
371	892	55	960,691
371	893	24	802,759
371	897	1	3,571
371		80	1,767,021

4/06/16 04.49.06 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,669,817
372		893	31	4,835,575
372			49	8,505,392
373		893	1	630,634
373			1	630,634
381		831	2	
381			2	
STATE	TOTAL:		178,853	37,554,821

5/5/2016 04.49.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
101	801	2	
101		2	
301	801	160,429	7,979,550
301	802	40	1,836
301		160,469	7,981,386
302	810	1	1,657
302	811	17,321	3,901,413
302	818	1	2,835
302		17,323	3,905,905
311	801	2	86
311		2	86
331	809	1	116,887
331	811	26	217,891
331	812	17	157,349
331		44	492,127
341	812	2	7,885
341		2	7,885
352	811	344	1,119,340
352		344	1,119,340
360	953	1	540,000
360		1	540,000
365	953	7	65,716
365		7	65,716
371	892	55	746,839

5/5/2016 04.49.25 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	24	733,088
371		897	1	4,476
371			80	1,484,403
372		892	18	3,237,752
372		893	31	4,353,221
372			49	7,590,973
373		893	1	485,081
373			1	485,081
381		831	2	
381			2	
STATE	TOTAL:		178,326	23,672,902

6/4/2016 04.50.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
101	801	1	4
101		1	4
301	801	160,060	3,848,527
301	802	41	859
301		160,101	3,849,386
302	810	1	1,707
302	811	17,216	2,614,094
302	818	1	4,790
302		17,218	2,620,591
311	801	1	54
311		1	54
331	809	1	123,813
331	811	26	182,597
331	812	18	133,086
331		45	439,496
341	812	2	35,442
341		2	35,442
352	811	346	721,923
352		346	721,923
365	953	7	70,668
365		7	70,668
371	892	54	656,327
371	893	24	635,858
371	897	1	5,832
371		79	1,298,017

6/4/2016 04.50.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,125,658
372		893	31	4,284,320
372			49	7,409,978
373		893	1	383,364
373			1	383,364
381		831	2	
381			2	
STATE	TOTAL:		177,852	16,828,923

7/7/2016 04.48.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,768	2,712,393
301	802	40	648
301		159,808	2,713,041
302	811	16,924	2,122,682
302		16,924	2,122,682
311	801	1	-760
311		1	-760
331	809	1	137,078
331	811	25	135,449
331	812	20	123,726
331		46	396,253
341	812	2	13,314
341		2	13,314
352	811	544	730,693
352	818	1	6,754
352		545	737,447
365	953	7	88,139
365		7	88,139
371	892	56	520,662
371	893	25	581,882
371	897	1	4,201
371		82	1,106,745
372	892	18	2,934,324
372	893	31	3,771,808
372		49	6,706,132

7/7/2016 04.48.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	355,636
373			1	355,636
381		831	2	
381			2	
STATE	TOTAL:		177,467	14,238,629

8/4/2016 04.49.12 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,409	1,888,081
301	802	40	584
301		159,449	1,888,665
302	811	16,834	1,726,429
302		16,834	1,726,429
331	809	1	108,422
331	811	27	139,739
331	812	19	116,413
331		47	364,574
341	812	2	21
341		2	21
352	811	543	543,203
352	818	1	6,890
352		544	550,093
365	953	7	110,771
365		7	110,771
371	892	55	508,161
371	893	25	550,018
371	897	1	6,204
371		81	1,064,383
372	892	18	3,045,729
372	893	31	3,802,732
372		49	6,848,461
373	893	1	353,198
373		1	353,198

8/4/2016 04.49.12 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
381		831	2
381			2
STATE	TOTAL:	177,016	12,906,595

9/7/2016 04.48.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,394	1,689,983
301	802	41	507
301		159,435	1,690,490
302	811	16,805	1,677,616
302		16,805	1,677,616
311	801	1	-364
311		1	-364
331	809	1	129,122
331	811	26	155,067
331	812	19	123,471
331		46	407,660
341	812	2	12,853
341		2	12,853
352	811	542	529,093
352	818	1	4,835
352		543	533,928
365	953	7	61,495
365		7	61,495
371	892	55	530,624
371	893	25	584,206
371	897	1	7,772
371		81	1,122,602
372	892	18	3,164,711
372	893	31	3,927,965
372		49	7,092,676

9/7/2016 04.48.14 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	384,055
373			1	384,055
381		831	2	
381			2	
STATE	TOTAL:		176,972	12,983,011

10/6/2016 10.47.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,136	1,870,719
301	802	41	615
301		159,177	1,871,334
302	811	16,756	1,891,295
302		16,756	1,891,295
328	951	1	14,820
328		1	14,820
331	809	1	119,067
331	811	26	153,186
331	812	19	126,645
331		46	398,898
341	812	2	21,385
341		2	21,385
352	811	541	593,061
352	818	1	5,511
352		542	598,572
365	953	7	85,807
365		7	85,807
371	892	55	557,599
371	893	25	573,041
371	897	1	7,832
371		81	1,138,472
372	892	18	3,058,528
372	893	31	3,789,074
372		49	6,847,602

10/6/2016 10.47.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	363,826
373			1	363,826
381		831	2	
381			2	
STATE	TOTAL:		176,664	13,232,011

11/4/2016 04.50.34 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	159,348	1,994,051
301	802	41	514
301		159,389	1,994,565
302	811	16,735	1,874,459
302		16,735	1,874,459
331	809	1	116,168
331	811	26	174,712
331	812	18	142,684
331		45	433,564
341	812	2	21,764
341		2	21,764
352	811	542	670,566
352	818	1	3,221
352		543	673,787
365	953	7	61,578
365		7	61,578
371	892	55	669,217
371	893	26	638,288
371	897	1	7,590
371		82	1,315,095
372	892	18	3,008,445
372	893	30	3,870,126
372		48	6,878,571
373	893	1	395,686
373		1	395,686

11/4/2016 04.50.34 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
381		831	2
381			2
STATE	TOTAL:	176,854	13,649,069

12/6/2016 04.50.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	160,217	3,985,030
301	802	41	1,031
301		160,258	3,986,061
302	811	16,814	2,552,763
302		16,814	2,552,763
313	802	1	6
313		1	6
331	809	1	112,107
331	811	26	288,438
331	812	18	204,690
331		45	605,235
341	812	2	15,597
341		2	15,597
352	811	542	1,013,466
352	818	1	3,305
352		543	1,016,771
360	953	1	10,069,780
360		1	10,069,780
365	953	7	46,528
365		7	46,528
371	892	55	912,365
371	893	26	761,642
371	897	1	6,133
371		82	1,680,140

12/6/2016 04.50.04 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,349,668
372		893	32	4,553,051
372			50	7,902,719
373		893	1	525,089
373			1	525,089
381		831	2	
381			2	
STATE	TOTAL:		177,806	28,400,689

1/6/2017 04.47.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-16

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	162,057	14,827,990
301	802	41	3,446
301		162,098	14,831,436
302	811	17,094	6,340,099
302		17,094	6,340,099
311	801	9	578
311		9	578
313	802	3	97
313		3	97
331	809	1	108,345
331	811	26	568,767
331	812	19	358,104
331		46	1,035,216
341	812	2	21,486
341		2	21,486
352	811	541	2,469,452
352	818	1	1,957
352		542	2,471,409
360	953	1	10,405,770
360		1	10,405,770
365	953	7	62,022
365		7	62,022
371	892	56	1,315,043
371	893	25	970,202

1/6/2017 04.47.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-16

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		897	1	6,702
371			82	2,291,947
372		892	18	4,502,131
372		893	32	5,611,352
372			50	10,113,483
373		893	1	737,581
373			1	737,581
381		831	2	
381			2	
STATE	TOTAL:		179,937	48,311,124

2/4/2017 04.48.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,295	21,274,978
301	802	41	4,213
301		163,336	21,279,191
302	810	1	2,054
302	811	17,299	8,596,045
302		17,300	8,598,099
311	801	20	-578
311		20	-578
313	802	8	-97
313		8	-97
331	809	1	110,777
331	811	26	481,065
331	812	19	328,623
331		46	920,465
341	812	2	18,455
341		2	18,455
352	811	547	3,194,095
352	818	1	2,341
352		548	3,196,436
360	953	1	10,481,630
360		1	10,481,630
365	953	7	81,876
365		7	81,876
371	892	54	1,213,047

2/4/2017 04.48.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	25	945,410
371		897	1	7,937
371			80	2,166,394
372		892	18	4,235,371
372		893	31	5,735,368
372			49	9,970,739
373		893	1	768,708
373			1	768,708
381		831	2	
381			2	
STATE	TOTAL:		181,400	57,481,318

3/4/2017 04.48.22 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,551	16,256,845
301	802	41	3,607
301		163,592	16,260,452
302	810	1	1,769
302	811	17,362	6,771,539
302		17,363	6,773,308
331	809	1	104,479
331	811	27	350,502
331	812	19	246,951
331		47	701,932
341	812	2	13,565
341		2	13,565
352	811	545	2,463,009
352	818	1	2,548
352		546	2,465,557
360	953	1	9,390,720
360		1	9,390,720
365	953	7	9,244
365		7	9,244
371	892	54	979,808
371	893	25	818,464
371	897	1	10,353
371		80	1,808,625
372	892	18	3,494,850
372	893	31	4,799,448

3/4/2017 04.48.22 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			49	8,294,298
373		893	1	668,393
373			1	668,393
381		831	3	
381			3	
STATE	TOTAL:		181,691	46,386,094

4/06/17 04.48.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,759	12,160,895
301	802	41	2,659
301		163,800	12,163,554
302	810	1	1,209
302	811	17,336	5,312,284
302		17,337	5,313,493
331	809	1	124,942
331	811	26	388,939
331	812	19	247,561
331	818	1	21
331		47	761,463
341	812	2	17,323
341		2	17,323
352	811	543	1,978,912
352	818	1	2,017
352		544	1,980,929
360	953	1	10,402,360
360		1	10,402,360
365	953	7	133,406
365		7	133,406
371	892	55	998,678
371	893	25	833,918
371	897	1	13,068
371		81	1,845,664
372	892	18	3,725,981

4/06/17 04.48.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		893	31	5,163,143
372			49	8,889,124
373		893	1	680,227
373			1	680,227
381		831	3	99
381			3	99
STATE	TOTAL:		181,872	42,187,642

5/04/17 04.46.50 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,571	8,306,370
301	802	41	1,724
301		163,612	8,308,094
302	810	1	924
302	811	17,274	3,797,761
302		17,275	3,798,685
311	801	1	14
311		1	14
331	809	1	109,038
331	811	26	196,010
331	812	19	138,265
331	818	1	16,288
331		47	459,601
341	812	2	20,539
341		2	20,539
352	811	545	1,407,837
352	818	1	2,587
352		546	1,410,424
360	953	1	4,576,500
360		1	4,576,500
365	953	7	113,437
365		7	113,437
371	892	54	667,786
371	893	25	610,909
371	897	1	8,685

5/04/17 04.46.50 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371			80	1,287,380
372		892	18	3,113,800
372		893	31	4,127,418
372			49	7,241,218
373		893	1	422,273
373			1	422,273
381		831	3	22
381			3	22
STATE	TOTAL:		181,624	27,638,187

6/06/17 04.45.35 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,484	3,465,986
301	802	41	736
301		163,525	3,466,722
302	810	1	84
302	811	17,209	2,321,709
302		17,210	2,321,793
331	809	1	118,292
331	811	26	188,098
331	812	18	162,978
331	818	1	31,769
331		46	501,137
341	812	2	12,983
341		2	12,983
352	811	541	857,790
352	818	1	4,184
352		542	861,974
360	953	1	3,157,660
360		1	3,157,660
365	953	7	19,295
365		7	19,295
371	892	54	619,974
371	893	24	609,691
371	897	1	7,418
371		79	1,237,083
372	892	18	3,205,822

6/06/17 04.45.35 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		893	30	4,128,679
372			48	7,334,501
373		893	1	417,770
373			1	417,770
381		831	3	11
381			3	11
STATE	TOTAL:		181,464	19,330,929

7/07/17 14.13.30 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	163,145	2,535,526
301	802	41	709
301		163,186	2,536,235
302	810	1	
302	811	17,211	2,133,039
302		17,212	2,133,039
331	809	1	
331	811	26	172,868
331	812	18	124,866
331	818	1	33,544
331		46	331,278
341	812	2	35,179
341		2	35,179
352	811	463	651,111
352	818	1	5,732
352		464	656,843
365	953	7	24,101
365		7	24,101
371	892	54	514,989
371	893	23	598,939
371	897	2	132,954
371		79	1,246,882
372	892	18	2,761,618
372	893	30	3,799,346
372		48	6,560,964

7/07/17 14.13.30 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	349,716
373			1	349,716
381		831	3	44
381			3	44
STATE	TOTAL:		181,048	13,874,281

8/4/2017 04.45.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	162,607	1,968,510
301	802	41	595
301		162,648	1,969,105
302	810	1	
302	811	17,133	1,869,594
302		17,134	1,869,594
311	801	2	6
311		2	6
328	952	1	38,898
328		1	38,898
331	811	26	151,225
331	812	18	122,610
331	818	1	35,613
331		45	309,448
341	812	2	4,265
341		2	4,265
352	811	461	584,172
352	818	1	6,287
352		462	590,459
360	953	1	6,176,480
360		1	6,176,480
365	953	7	54,380
365		7	54,380
371	892	54	496,572

8/4/2017 04.45.23 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	23	559,178
371		897	2	126,344
371			79	1,182,094
372		892	18	2,717,493
372		893	30	3,706,823
372			48	6,424,316
373		893	1	357,851
373			1	357,851
381		831	3	121
381			3	121
STATE	TOTAL:		180,433	18,977,017

9/7/2017 04.45.41 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	162,768	1,758,175
301	802	41	523
301		162,809	1,758,698
302	810	1	
302	811	17,134	1,913,710
302		17,135	1,913,710
311	801	1	7
311		1	7
331	811	26	175,555
331	812	18	138,255
331	818	1	33,457
331		45	347,267
341	812	2	9,408
341		2	9,408
352	811	461	546,834
352	818	1	4,904
352		462	551,738
360	953	1	3,163,550
360		1	3,163,550
365	953	7	142,957
365		7	142,957
371	892	54	560,179
371	893	23	654,619
371	897	2	138,574
371		79	1,353,372

9/7/2017 04.45.41 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,002,052
372		893	30	2,884,696
372			48	5,886,748
373		893	1	396,797
373			1	396,797
381		831	3	121
381			3	121
STATE	TOTAL:		180,593	15,524,373

10/5/2017 04.44.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	162,447	2,078,263
301	802	41	627
301		162,488	2,078,890
302	810	1	
302	811	17,079	1,924,206
302		17,080	1,924,206
311	801	2	6
311		2	6
331	811	26	180,453
331	812	18	134,493
331	818	1	28,392
331		45	343,338
341	812	2	11,283
341		2	11,283
352	811	458	641,159
352	818	1	3,635
352		459	644,794
360	953	1	3,061,500
360		1	3,061,500
365	953	7	1,444
365		7	1,444
371	892	54	590,540
371	893	23	606,112
371	897	2	127,341
371		79	1,323,993

10/5/2017 04.44.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,048,545
372		893	30	2,723,996
372			48	5,772,541
373		893	1	385,654
373			1	385,654
381		831	3	165
381			3	165
STATE	TOTAL:		180,215	15,547,814

11/6/2017 11.25.48 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	162,749	2,232,198
301	802	41	580
301		162,790	2,232,778
302	810	1	
302	811	17,081	2,061,359
302		17,082	2,061,359
311	801	1	6
311		1	6
313	802	1	
313		1	
331	811	26	242,731
331	812	18	179,725
331	818	1	30,162
331		45	452,618
341	812	2	30,936
341		2	30,936
352	811	460	721,127
352	818	1	3,239
352		461	724,366
360	953	1	4,745,480
360		1	4,745,480
365	953	7	337,896
365		7	337,896
371	892	52	796,187

11/6/2017 11.25.48 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	24	731,066
371		897	2	136,905
371			78	1,664,158
372		892	18	3,235,178
372		893	30	3,247,214
372			48	6,482,392
373		893	1	461,687
373			1	461,687
381		831	3	551
381			3	551
STATE	TOTAL:		180,520	19,194,227

12/6/2017 04.45.05 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	164,060	7,767,672
301	802	41	1,828
301		164,101	7,769,500
302	810	1	
302	811	17,220	4,067,386
302		17,221	4,067,386
311	801	1	-23
311		1	-23
313	802	2	34
313		2	34
331	811	27	392,898
331	812	18	257,617
331	818	1	28,710
331		46	679,225
341	812	2	40,811
341		2	40,811
352	811	459	1,509,261
352	818	1	2,359
352		460	1,511,620
360	953	1	300,000
360		1	300,000
365	953	7	17,441
365		7	17,441
371	892	52	1,015,206

12/6/2017 04.45.05 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	24	876,222
371		897	2	126,009
371			78	2,017,437
372		892	18	3,587,087
372		893	30	4,645,849
372			48	8,232,936
373		893	1	659,937
373			1	659,937
381		831	3	1,525
381			3	1,525
STATE	TOTAL:		181,971	25,297,829

1/5/2018 04.45.09 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-17

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	165,556	16,115,920
301	802	41	3,600
301		165,597	16,119,520
302	810	1	
302	811	17,424	6,830,906
302		17,425	6,830,906
313	802	1	78
313		1	78
328	951	1	10,193
328		1	10,193
331	811	26	626,639
331	812	18	386,626
331	818	1	29,097
331		45	1,042,362
341	812	2	41,307
341		2	41,307
352	811	460	2,313,325
352	818	1	1,432
352		461	2,314,757
365	953	7	87,166
365		7	87,166
371	892	52	1,389,476
371	893	24	1,018,999
371	897	2	122,696
371		78	2,531,171

STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-17

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	4,341,265
372		893	30	5,307,034
372			48	9,648,299
373		893	1	734,033
373			1	734,033
381		831	3	2,928
381			3	2,928
STATE	TOTAL:		183,669	39,362,720

2/6/2018 04.45.55 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	166,576	31,962,586
301	802	41	7,001
301		166,617	31,969,587
302	810	1	2,108
302	811	17,560	13,597,996
302		17,561	13,600,104
313	802	1	150
313		1	150
328	951	2	40,612
328	952	1	74,720
328		3	115,332
331	811	26	766,434
331	812	17	444,604
331	818	1	30,669
331		44	1,241,707
341	812	2	32,497
341		2	32,497
352	811	458	4,153,038
352	818	1	1,405
352		459	4,154,443
360	953	1	392,000
360		1	392,000
365	953	7	42,643
365		7	42,643

2/6/2018 04.45.55 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		892	52	1,598,396
371		893	24	1,189,088
371		897	2	126,560
371			78	2,914,044
372		892	18	4,852,755
372		893	30	5,845,456
372			48	10,698,211
373		893	1	605,379
373			1	605,379
381		831	3	3,506
381			3	3,506
STATE	TOTAL:		184,825	65,769,603

3/6/2018 04.46.07 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	167,182	24,612,277
301	802	42	5,831
301		167,224	24,618,108
302	810	1	3,195
302	811	17,637	9,940,688
302		17,638	9,943,883
313	802	1	73
313		1	73
328	951	1	2,922
328	952	1	14,149
328		2	17,071
331	811	26	440,333
331	812	19	291,803
331	818	1	28,242
331		46	760,378
341	812	2	16,603
341		2	16,603
352	811	461	2,924,912
352	818	1	955
352		462	2,925,867
365	953	7	26,092
365		7	26,092
371	892	52	1,060,487
371	893	24	960,371
371	897	2	117,006

3/6/2018 04.46.07 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371			78	2,137,864
372		892	18	3,607,346
372		893	30	4,770,435
372			48	8,377,781
373		893	1	591,204
373			1	591,204
381		831	3	1,743
381			3	1,743
STATE	TOTAL:		185,512	49,416,667

4/5/2018 04.47.48 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	167,325	13,050,620
301	802	41	2,935
301		167,366	13,053,555
302	810	1	2,134
302	811	17,614	5,974,074
302		17,615	5,976,208
313	802	1	41
313		1	41
328	951	3	40,123
328	952	1	11,272
328		4	51,395
331	811	26	454,589
331	812	19	303,977
331	818	1	31,342
331		46	789,908
341	812	2	19,005
341		2	19,005
352	811	462	1,647,324
352	818	1	501
352		463	1,647,825
365	953	7	
365		7	
371	892	52	1,162,094
371	893	24	960,338
371	897	2	124,796

4/5/2018 04.47.48 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371			78	2,247,228
372		892	18	3,782,983
372		893	30	5,168,005
372			48	8,950,988
373		893	1	666,519
373			1	666,519
381		831	3	1,707
381			3	1,707
STATE	TOTAL:		185,634	33,404,379

5/4/2018 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	167,334	12,939,749
301	802	41	2,788
301		167,375	12,942,537
302	810	1	1,963
302	811	17,595	5,714,149
302		17,596	5,716,112
313	802	1	31
313		1	31
328	951	1	34,280
328		1	34,280
331	811	26	349,232
331	812	18	248,829
331	818	1	29,889
331		45	627,950
341	812	2	16,468
341		2	16,468
352	811	461	1,901,353
352	818	1	726
352		462	1,902,079
365	953	7	151,028
365		7	151,028
371	892	52	975,929
371	893	24	871,209
371	897	2	125,971
371		78	1,973,109

5/4/2018 04.47.57 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,551,146
372		893	30	4,969,828
372			48	8,520,974
373		893	1	526,413
373			1	526,413
381		831	3	1,185
381			3	1,185
STATE	TOTAL:		185,619	32,412,166

6/6/2018 5.28.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	167,237	6,266,809
301		802	42	1,262
301			167,279	6,268,071
302		810	1	1,127
302		811	17,552	3,314,103
302			17,553	3,315,230
313		802	1	
313			1	
331		811	26	184,390
331		812	18	132,265
331		818	1	33,444
331			45	350,099
341		812	2	20,600
341			2	20,600
352		811	464	1,076,675
352		818	1	1,306
352			465	1,077,981
365		953	7	14,471
365			7	14,471
371		892	53	581,315
371		893	24	685,857
371		897	2	142,995
371			79	1,410,167
372		892	18	3,203,609
372		893	30	4,006,248

6/6/2018 5.28.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			48	7,209,857
373		893	1	428,429
373			1	428,429
381		831	3	431
381			3	431
STATE	TOTAL:		185,483	20,095,336

7/6/2018 5.32.40 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	166,564	2,289,894
301	802	40	668
301		166,604	2,290,562
302	810	1	65
302	811	17,436	2,104,256
302		17,437	2,104,321
313	802	1	
313		1	
331	811	28	181,437
331	812	17	105,791
331	818	1	33,652
331		46	320,880
341	812	2	37,443
341		2	37,443
352	811	460	658,030
352	818	1	
352		461	658,030
360	953	1	420,000
360		1	420,000
365	953	8	54,307
365		8	54,307
371	892	52	517,018
371	893	26	636,608
371	897	2	135,033
371		80	1,288,659

7/6/2018 5.32.40 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	2,962,992
372		893	30	3,565,907
372			48	6,528,899
373		893	1	409,368
373			1	409,368
381		831	3	274
381			3	274
STATE	TOTAL:		184,692	14,112,743

8/4/2018 5.23.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	166,166	1,826,627
301		802	40	649
301			166,206	1,827,276
302		810	1	
302		811	17,381	1,821,263
302			17,382	1,821,263
311		801	1	
311			1	
313		802	1	
313			1	
331		811	28	179,274
331		812	17	104,489
331		818	1	35,833
331			46	319,596
341		812	2	5,241
341			2	5,241
352		811	459	558,641
352		818	1	32
352			460	558,673
365		953	8	22,908
365			8	22,908
371		892	52	491,326
371		893	24	583,254
371		897	2	139,783
371			78	1,214,363

8/4/2018 5.23.26 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,165,931
372		893	30	3,579,962
372			48	6,745,893
373		893	1	369,509
373			1	369,509
381		831	3	264
381			3	264
STATE	TOTAL:		184,236	12,884,986

9/7/2018 6.09.46 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	165,957	1,719,000
301		802	40	601
301			165,997	1,719,601
302		810	1	
302		811	17,327	1,833,630
302			17,328	1,833,630
311		801	1	
311			1	
313		802	1	
313			1	
331		811	27	186,515
331		812	18	126,137
331		818	1	35,921
331			46	348,573
341		812	2	8,988
341			2	8,988
352		811	462	540,639
352		818	1	32
352			463	540,671
365		953	8	8,237
365			8	8,237
371		892	52	530,798
371		893	24	676,155
371		897	2	146,932
371			78	1,353,885

9/7/2018 6.09.46 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	18	3,216,327
372		893	30	3,566,837
372			48	6,783,164
373		893	1	434,024
373			1	434,024
381		831	3	297
381			3	297
STATE	TOTAL:		183,976	13,031,070

10/4/2018 6.07.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	165,515	1,950,075
301		802	40	668
301			165,555	1,950,743
302		810	1	
302		811	17,259	2,006,548
302			17,260	2,006,548
311		801	1	
311			1	
313		802	1	-407
313			1	-407
331		811	29	178,586
331		812	19	135,278
331		818	1	34,507
331			49	348,371
341		812	2	25,931
341			2	25,931
352		811	455	586,664
352		818	1	32
352			456	586,696
360		953	1	310,000
360			1	310,000
365		953	8	31,506
365			8	31,506
371		892	52	544,590

10/4/2018 6.07.45 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	24	605,019
371		897	2	130,141
371			78	1,279,750
372		892	18	3,121,564
372		893	30	3,270,592
372			48	6,392,156
373		893	1	425,961
373			1	425,961
381		831	3	349
381			3	349
STATE	TOTAL:		183,463	13,357,604

11/6/2018 6.00.39 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	165,808	2,415,053
301		802	40	705
301			165,848	2,415,758
302		810	1	
302		811	17,264	2,179,791
302			17,265	2,179,791
311		801	1	
311			1	
313		802	2	-217
313			2	-217
328		951	1	14,524
328			1	14,524
331		811	29	428,384
331		812	18	203,633
331		818	1	34,297
331			48	666,314
341		812	2	36,189
341			2	36,189
352		811	456	700,096
352		818	1	43
352			457	700,139
365		953	8	112,585
365			8	112,585
371		892	53	841,758

11/6/2018 6.00.39 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
371		893	24	757,965
371		897	2	146,174
371			79	1,745,897
372		892	18	3,475,001
372		893	30	4,463,999
372			48	7,939,000
373		893	1	564,468
373			1	564,468
381		831	3	857
381			3	857
STATE	TOTAL:		183,763	16,375,305

12/6/2018 6.11.11 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-18

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	167,294	10,304,049
301	802	42	2,969
301		167,336	10,307,018
302	810	1	31
302	811	17,457	5,194,610
302		17,458	5,194,641
328	951	1	578
328		1	578
331	811	29	477,663
331	812	19	339,438
331	818	1	30,759
331		49	847,860
341	812	2	38,910
341		2	38,910
352	811	456	1,732,494
352	818	1	11
352		457	1,732,505
365	953	8	82,700
365		8	82,700
371	892	53	1,237,538
371	893	24	953,583
371	897	2	136,704
371		79	2,327,825
372	892	19	4,149,606
372	893	30	5,145,495

12/6/2018 6.11.11 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			49	9,295,101
373		893	1	743,497
373			1	743,497
381		831	3	2,826
381			3	2,826
STATE	TOTAL:		185,443	30,573,461

1/5/2019 6.10.36 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	168,880	19,987,572
301		802	44	4,777
301			168,924	19,992,349
302		810	1	1,283
302		811	17,667	8,555,925
302			17,668	8,557,208
311		801	1	
311			1	
331		811	30	644,800
331		812	18	372,704
331		818	1	30,555
331			49	1,048,059
341		812	2	27,269
341			2	27,269
352		811	457	2,627,974
352		818	1	
352			458	2,627,974
365		953	8	8,796
365			8	8,796
371		892	53	1,356,916
371		893	24	992,056
371		897	2	130,456
371			79	2,479,428
372		892	19	4,381,919
372		893	30	5,262,719

1/5/2019 6.10.36 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-18

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372			49	9,644,638
373		893	1	787,698
373			1	787,698
381		831	3	3,181
381			3	3,181
STATE	TOTAL:		187,242	45,176,600

2/06/19 6.11.05 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	169,574	21,056,522
301	802	44	5,238
301	804	1	563
301		169,619	21,062,323
302	810	1	1,363
302	811	17,765	9,392,526
302		17,766	9,393,889
331	811	30	691,660
331	812	18	430,015
331	818	1	31,059
331		49	1,152,734
341	812	2	26,745
341		2	26,745
352	811	459	2,835,519
352	818	1	192
352		460	2,835,711
365	953	8	52,315
365		8	52,315
371	892	53	1,524,649
371	893	24	1,103,739
371	897	2	149,980
371		79	2,778,368
372	892	19	4,477,924
372	893	30	5,924,477
372		49	10,402,401

2/06/19 6.11.05 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jan-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	766,201
373			1	766,201
381		831	3	4,033
381			3	4,033
STATE	TOTAL:		188,036	48,474,720

3/6/2019 6.11.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	169,793	23,383,978
301		802	44	5,353
301			169,837	23,389,331
302		810	1	1,211
302		811	17,778	9,671,072
302			17,779	9,672,283
331		811	30	532,888
331		812	18	313,825
331		818	1	28,386
331			49	875,099
341		812	2	16,843
341			2	16,843
352		811	459	2,887,034
352		818	1	383
352			460	2,887,417
365		953	8	98,563
365			8	98,563
371		892	53	1,137,470
371		893	24	865,443
371		897	2	131,397
371			79	2,134,310
372		892	19	3,681,811
372		893	30	5,042,412
372			49	8,724,223
373		893	1	661,097

3/6/2019 6.11.56 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	661,097
381		831	3	2,493
381			3	2,493
STATE	TOTAL:		188,267	48,461,659

4/4/2019 6.15.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	169,982	18,025,571
301		802	44	3,884
301			170,026	18,029,455
302		810	1	1,635
302		811	17,783	7,853,310
302			17,784	7,854,945
331		811	30	555,713
331		812	16	326,567
331		818	1	31,421
331			47	913,701
341		812	3	17,383
341			3	17,383
352		811	460	2,353,642
352		818	1	277
352			461	2,353,919
365		953	8	10,843
365			8	10,843
371		892	53	1,184,681
371		893	24	962,577
371		897	2	138,055
371			79	2,285,313
372		892	19	3,977,851
372		893	30	5,445,372
372			49	9,423,223
373		893	1	681,758

4/4/2019 6.15.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	681,758
381		831	3	2,630
381			3	2,630
STATE	TOTAL:		188,461	41,573,170

5/4/2019 6.10.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	170,053	10,704,415
301	802	44	2,369
301		170,097	10,706,784
302	810	1	1,327
302	811	17,770	5,095,999
302		17,771	5,097,326
331	811	31	320,322
331	812	16	177,669
331	818	1	30,983
331		48	528,974
341	812	2	13,788
341		2	13,788
352	811	458	1,519,409
352	818	1	736
352		459	1,520,145
365	953	8	5,693
365		8	5,693
371	892	53	787,837
371	893	24	731,479
371	897	2	147,280
371		79	1,666,596
372	892	19	3,071,662
372	893	30	4,247,770
372		49	7,319,432
373	893	1	519,805

5/4/2019 6.10.13 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Apr-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373			1	519,805
381		831	3	988
381			3	988
STATE	TOTAL:		188,517	27,379,531

6/6/2019 6.16.44 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	169,556	4,179,365
301	802	44	972
301		169,600	4,180,337
302	810	1	746
302	811	17,649	2,718,514
302		17,650	2,719,260
311	801	1	
311		1	
331	811	31	261,055
331	812	16	125,599
331	818	1	33,612
331		48	420,266
341	812	2	9,094
341		2	9,094
352	811	462	842,963
352	818	1	3,172
352		463	846,135
360	953	1	410,000
360		1	410,000
365	953	8	31,972
365		8	31,972
371	892	52	637,424
371	893	24	664,286
371	897	2	148,148
371		78	1,449,858

6/6/2019 6.16.44 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: May-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
372		892	19	3,172,307
372		893	30	3,731,035
372			49	6,903,342
373		893	1	449,306
373			1	449,306
381		831	3	542
381			3	542
STATE	TOTAL:		187,904	17,420,112

7/4/2019 6.10.59 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	169,042	2,501,322
301		802	43	730
301			169,085	2,502,052
302		811	17,426	2,129,356
302			17,426	2,129,356
331		811	34	230,261
331		812	16	109,270
331		818	1	33,996
331			51	373,527
341		812	2	12,359
341			2	12,359
352		811	563	720,606
352		818	1	4,213
352			564	724,819
365		953	8	18,988
365			8	18,988
371		892	51	574,552
371		893	24	602,712
371		897	2	139,634
371			77	1,316,898
372		892	19	2,999,080
372		893	30	3,484,774
372			49	6,483,854
373		893	1	424,497
373			1	424,497

7/4/2019 6.10.59 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jun-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	500
381			3	500
STATE	TOTAL:		187,266	13,986,850

8/6/2019 6.15.30 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	169,014	2,011,416
301	802	42	630
301		169,056	2,012,046
302	811	17,391	1,982,692
302		17,391	1,982,692
331	811	35	224,393
331	812	16	112,860
331	818	1	38,219
331		52	375,472
341	812	2	9,547
341		2	9,547
352	811	565	684,020
352	818	1	4,804
352		566	688,824
365	953	8	20,674
365		8	20,674
371	892	51	533,942
371	893	23	580,854
371	897	2	151,495
371		76	1,266,291
372	892	19	3,017,058
372	893	30	3,712,735
372		49	6,729,793
373	893	1	348,205
373		1	348,205

8/6/2019 6.15.30 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Jul-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	675
381			3	675
STATE	TOTAL:		187,204	13,434,219

9/6/2019 6.11.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	168,768	1,852,660
301	802	42	661
301		168,810	1,853,321
302	811	17,334	1,856,635
302		17,334	1,856,635
331	811	35	247,976
331	812	16	114,289
331	818	1	34,372
331		52	396,637
341	812	2	2,845
341		2	2,845
352	811	565	624,281
352	818	1	3,866
352		566	628,147
365	953	8	19,954
365		8	19,954
371	892	51	553,663
371	893	23	613,110
371	897	2	152,663
371		76	1,319,436
372	892	19	2,972,326
372	893	30	3,626,855
372		49	6,599,181
373	893	1	410,032
373		1	410,032

9/6/2019 6.11.00 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Aug-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	751
381			3	751
STATE	TOTAL:		186,901	13,086,939

10/4/2019 6.08.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	168,621	1,956,560
301		802	42	604
301			168,663	1,957,164
302		811	17,280	1,934,048
302			17,280	1,934,048
331		811	36	240,782
331		812	16	105,526
331		818	1	32,800
331			53	379,108
341		812	2	29,494
341			2	29,494
352		811	565	665,300
352		818	1	3,210
352			566	668,510
360		953	1	660,000
360			1	660,000
365		953	8	10,976
365			8	10,976
371		892	52	520,556
371		893	23	524,866
371		897	2	147,727
371			77	1,193,149
372		892	19	2,865,418
372		893	30	3,448,293
372			49	6,313,711

10/4/2019 6.08.43 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Sep-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
373		893	1	385,303
373			1	385,303
381		831	3	762
381			3	762
STATE	TOTAL:		186,703	13,532,225

11/6/2019 6.07.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	168,875	2,335,137
301		802	42	676
301			168,917	2,335,813
302		811	17,286	2,141,128
302			17,286	2,141,128
331		811	36	358,304
331		812	16	153,349
331		818	1	33,951
331			53	545,604
341		812	2	31,419
341			2	31,419
352		811	562	770,946
352		818	1	2,354
352			563	773,300
365		953	6	158,255
365			6	158,255
371		892	51	748,358
371		893	23	744,959
371		897	2	152,336
371			76	1,645,653
372		892	19	3,278,410
372		893	30	4,197,627
372			49	7,476,037
373		893	1	502,424
373			1	502,424

11/6/2019 6.07.49 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Oct-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	1,449
381			3	1,449
STATE	TOTAL:		186,956	15,611,082

12/5/2019 6.12.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
301		801	170,030	10,084,388
301		802	42	2,337
301			170,072	10,086,725
302		811	17,468	4,731,896
302			17,468	4,731,896
331		811	36	680,647
331		812	16	288,664
331		818	1	32,643
331			53	1,001,954
341		812	2	34,525
341			2	34,525
352		811	565	1,998,425
352		818	1	672
352			566	1,999,097
365		953	8	15,643
365			8	15,643
371		892	50	1,086,379
371		893	25	890,011
371		897	2	135,685
371			77	2,112,075
372		892	19	3,840,542
372		893	30	5,333,033
372			49	9,173,575
373		893	1	606,656
373			1	606,656

12/5/2019 6.12.38 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Nov-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	4,918
381			3	4,918
STATE	TOTAL:		188,299	29,767,064

1/7/2020 8.31.03 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-19

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	171,603	18,329,463
301	802	42	4,044
301		171,645	18,333,507
302	811	17,677	7,591,560
302		17,677	7,591,560
331	811	36	675,521
331	812	16	291,633
331	818	1	33,162
331		53	1,000,316
341	812	2	34,024
341		2	34,024
352	811	569	2,968,945
352	818	1	854
352		570	2,969,799
365	953	8	84,944
365		8	84,944
371	892	50	1,128,262
371	893	23	915,174
371	897	2	131,294
371		75	2,174,730
372	892	19	4,112,642
372	893	30	5,070,213
372		49	9,182,855
373	893	1	618,597
373		1	618,597

1/7/2020 8.31.03 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Dec-19

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	5,103
381			3	5,103
STATE	TOTAL:		190,083	41,995,435

2/06/20 6.16.37 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS
FOR THE MONTH: Jan-20

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	172,168	19,305,256
301	802	43	4,541
301		172,211	19,309,797
302	811	17,707	8,192,387
302		17,707	8,192,387
328	951	2	36,429
328		2	36,429
331	811	36	763,168
331	812	15	315,487
331	818	1	29,968
331		52	1,108,623
341	812	2	28,722
341		2	28,722
352	811	567	3,066,638
352	818	1	749
352		568	3,067,387
365	953	7	38,125
365		7	38,125
371	892	50	1,246,927
371	893	23	966,893
371	897	2	137,809
371		75	2,351,629
372	892	19	4,264,594
372	893	30	5,468,557
372		49	9,733,151
373	893	1	691,473

2/06/20 6.16.37 PIEDMONT NATURAL GAS ZCSRP620-B

STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS STATE TOTALS

FOR THE MONTH: Jan-20

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
373		1	691,473
381	831	3	6,129
381		3	6,129
STATE	TOTAL:	190,677	44,563,852

3/5/2020 6.18.33 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-20

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	172,551	21,223,007
301	802	43	5,253
301		172,594	21,228,260
302	811	17,766	8,638,174
302		17,766	8,638,174
331	811	36	735,197
331	812	15	319,545
331	818	1	27,375
331		52	1,082,117
341	812	2	29,104
341		2	29,104
352	811	570	3,240,669
352	818	1	172
352		571	3,240,841
365	953	7	84,681
365		7	84,681
371	892	50	1,222,049
371	893	23	959,142
371	897	2	126,824
371		75	2,308,015
372	892	19	3,999,213
372	893	30	5,285,040
372		49	9,284,253
373	893	1	601,926
373		1	601,926

3/5/2020 6.18.33 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Feb-20

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	5,895
381			3	5,895
STATE	TOTAL:		191,120	46,503,266

4/4/2020 6.06.32 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-20

RATE	CLASS	NUMBER OF BILLS	TOTAL THERMS
301	801	172,931	17,704,736
301	802	43	4,226
301		172,974	17,708,962
302	811	17,752	7,138,739
302		17,752	7,138,739
331	811	36	438,071
331	812	15	178,823
331	818	1	27,694
331		52	644,588
341	812	2	19,015
341		2	19,015
352	811	568	2,609,351
352	818	1	236
352		569	2,609,587
365	953	7	7,250
365		7	7,250
371	892	50	915,868
371	893	23	812,317
371	897	2	136,338
371		75	1,864,523
372	892	19	3,599,963
372	893	30	4,375,261
372		49	7,975,224
373	893	1	474,885
373		1	474,885

4/4/2020 6.06.32 PIEDMONT NATURAL GAS ZCSRP620-B
STATE: TN TOTAL BILL COUNT AND THERMS BY RATE/CLASS
FOR THE MONTH: Mar-20

RATE	CLASS		NUMBER OF BILLS	TOTAL THERMS
381		831	3	3,338
381			3	3,338
STATE	TOTAL:		191,484	38,446,111

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-14. Provide a complete copy of the Company's monthly 301C Reports in Excel and PDF format from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

RESPONSE: Please see the two attachments.

Name and Title of Preparer: Doug Templeton - Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Kally Couzens - Manager Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

Piedmont Natural Gas Company, Inc.

301C REPORT

Rate Key		
Description	Current Tariff Rate Schedule	Billing System Rate Code [1]
Residential Service	301	301/311/313
Small General Service	302	302/321/332
Medium General Service	352	352/366
Firm General Sales Service	303	331
Interruptible General Sales Service	304	341
Firm Transportation Service	313	371
Interruptible Transportation Service	314	372
Resale Service	310	381
Other System Tracking Rate Codes:		
Cash-out (off cycle)		328
Motor Vehicle Fuel *(prior to Mar 2015)*		342
Secondary Marketing		360
Emergency Service		361
Standby Sales		362
Cash-out		365
Special Contract		373

1/ Certain reports and queries run from the Piedmont billing system (such as 620B and 301C) reflect billing system rate codes, which may vary from those rate codes reflected in Piedmont's Tariff Rate Schedules.

The data for Tariff Rate Schedule 343 - Motor Vehicle Fuel Service is reflected in the corresponding billing rate schedule.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

May 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		30		$ 452.35	$ -	$ -	$ -	$ -
TN	311	49809	2,014,395	$ 2,066,430.03	$ -	$ 92,397.37	$ -	$ -
TN	313	101098	1,806,418	$ 2,470,338.39	$ 3.29	$ 128,446.30	$ -	$ -
TN	321	12667	582,124	$ 842,723.41	$ 34,794.54	$ 48,897.00	$ -	$ -
TN	328	1	73,445	$ 34,724.80	$ 556.97	$ 2,406.43	$ -	$ -
TN	331	43	291,877	$ 273,228.84	$ 7,298.83	$ 17,241.43	$ -	$ -
TN	332	4068	1,692,883	$ 1,488,208.54	$ 93,949.72	$ 86,602.70	$ -	$ -
TN	341	2	4,460	$ 3,233.01	$ 219.54	$ 224.05	$ -	$ -
TN	352	285	239,458	$ 214,367.80	$ 3,046.14	$ 12,930.17	$ -	$ -
TN	365	18	19,327	$ 8,595.50	$ -	$ -	$ -	$ -
TN	366	169	491,411	$ 408,739.45	$ 9,770.97	$ 25,855.64	$ -	$ -
TN	371	90	2,336,021	$ 511,565.14	$ -	$ 34,543.27	$ -	$ -
TN	372	54	4,375,481	$ 273,483.44	$ -	$ 18,476.82	$ -	$ -
TN	373	4	1,777,387	$ 97,054.64	$ -	$ -	$ -	$ -
TN	381	2	2,138	$ 26,655.31	$ -	$ -	$ -	$ -
TN Totals		**168,340**	**15,706,825**	**$ 8,719,800.65**	**$ 149,640.00**	**$ 468,021.18**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

June 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		31		$ 628.65	$ -	$ -	$ -	$ -
TN	311	49744	1,550,656	$ 1,705,060.95	$ -	$ 76,734.05	$ -	$ -
TN	313	100373	1,041,208	$ 1,844,141.15	$ 2.98	$ 97,302.14	$ -	$ -
TN	321	12594	296,642	$ 605,318.04	$ 37,800.09	$ 35,824.72	$ -	$ -
TN	331	41	224,119	$ 236,197.92	$ 6,399.63	$ 14,704.03	$ -	$ -
TN	332	3737	1,511,941	$ 1,333,099.52	$ 90,547.25	$ 77,230.10	$ -	$ -
TN	341	2		$ 600.00	$ 22.46	$ 41.58	$ -	$ -
TN	352	344	154,096	$ 150,177.38	$ 7,298.76	$ 8,709.27	$ -	$ -
TN	365	4	44,524	$ 21,951.35	$ 217.54	$ 939.92	$ -	$ -
TN	366	168	472,707	$ 393,811.97	$ 11,589.35	$ 25,366.62	$ -	$ -
TN	371	86	2,042,195	$ 485,797.15	$ -	$ 32,657.85	$ -	$ -
TN	372	53	3,873,570	$ 249,214.91	$ -	$ 16,845.40	$ -	$ -
TN	373	2	1,596,799	$ 92,512.10	$ -	$ -	$ -	$ -
TN	381	2	1,208	$ 4,302.77	$ -	$ -	$ -	$ -
TN Totals		**167,181**	**12,809,665**	**$ 7,122,813.86**	**$ 153,878.06**	**$ 386,355.68**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

July 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		31		$ (444.10)	$ -	$ -	$ -	$ -
TN	311	49,647	1,140,639	$ 1,384,301.02	$ (2.28)	$ 63,856.07	$ -	$ -
TN	313	99,253	599,483	$ 1,475,907.52	$ 1.23	$ 79,495.78	$ -	$ -
TN	321	12,275	174,314	$ 499,522.76	$ 29,498.74	$ 29,596.13	$ -	$ -
TN	331	47	208,292	$ 232,534.17	$ (12,584.01)	$ 13,932.91	$ -	$ -
TN	332	3,704	1,381,142	$ 1,226,368.57	$ 82,666.48	$ 71,273.52	$ -	$ -
TN	341	2		$ 600.00	$ 22.46	$ 41.58	$ -	$ -
TN	352	350	102,796	$ 109,157.57	$ 5,172.61	$ 6,486.52	$ -	$ -
TN	360	1	116,040	$ 50,702.33	$ -	$ -	$ -	$ -
TN	365	7	434,732	$ 212,685.26	$ 8.14	$ 7.54	$ -	$ -
TN	366	147	425,245	$ 355,319.43	$ 14,941.26	$ 23,059.44	$ -	$ -
TN	371	88	1,955,248	$ 487,277.94	$ -	$ 32,809.50	$ -	$ -
TN	372	55	3,945,254	$ 247,712.76	$ -	$ 16,767.73	$ -	$ -
TN	373	2	1,597,307	$ 92,026.15	$ -	$ -	$ -	$ -
TN	381	2	1,099	$ 4,243.01	$ -	$ -	$ -	$ -
TN Totals		**165,611**	**12,081,591**	**$ 6,377,914.39**	**$ 119,724.63**	**$ 337,326.72**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

August 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		26		$ 340.46	$ -	$ -	$ -	$ -
TN	311	49,589	972,743	$ 1,253,386.88	$ 4.46	$ 57,474.94	$ -	$ -
TN	313	98,809	523,483	$ 1,410,077.74	$ -	$ 75,648.20	$ -	$ -
TN	321	12,137	153,106	$ 478,647.04	$ 28,703.33	$ 28,296.38	$ -	$ -
TN	328	1	1,911	$ 849.25	$ 63.57	$ 58.85	$ -	$ -
TN	331	44	222,214	$ 235,773.03	$ 6,359.88	$ 15,461.87	$ -	$ -
TN	332	3,663	1,273,174	$ 1,138,743.74	$ 76,497.21	$ 65,504.97	$ -	$ -
TN	341	2		$ 600.00	$ 22.46	$ 41.58	$ -	$ -
TN	352	345	99,283	$ 106,078.72	$ 4,603.64	$ 6,428.51	$ -	$ -
TN	365	9	34,110	$ 15,656.97	$ 9.63	$ 8.92	$ -	$ -
TN	366	143	372,555	$ 312,675.86	$ 12,981.12	$ 20,395.95	$ -	$ -
TN	371	86	2,068,348	$ 490,194.75	$ -	$ 32,973.92	$ -	$ -
TN	372	59	4,443,649	$ 270,665.74	$ -	$ 18,318.67	$ -	$ -
TN	373	4	641,505	$ 65,972.28	$ -	$ -	$ -	$ -
TN	381	2	1,210	$ 4,303.87	$ -	$ -	$ -	$ -
TN Totals		**164,919**	**10,807,291**	**$ 5,783,966.33**	**$ 129,245.30**	**$ 320,612.76**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

September 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		30		$ 148.56	$ -	$ -	$ -	$ -
TN	311	49,773	1,144,219	$ 1,388,552.66	$ 0.68	$ 64,206.02	$ -	$ -
TN	313	98,570	597,120	$ 1,467,169.44	$ 0.93	$ 78,953.37	$ -	$ -
TN	321	12,154	213,683	$ 529,906.90	$ 31,252.50	$ 31,421.79	$ -	$ -
TN	331	41	277,978	$ 267,260.22	$ 7,178.04	$ 16,805.35	$ -	$ -
TN	332	3,663	1,408,891	$ 1,249,016.49	$ 83,249.23	$ 73,061.81	$ -	$ -
TN	341	2	2,400	$ 2,016.86	$ 128.51	$ 139.77	$ -	$ -
TN	352	365	147,891	$ 146,236.18	$ 6,868.60	$ 7,979.96	$ -	$ -
TN	362	1	1,843	$ 721.17	$ -	$ -	$ -	$ -
TN	365	7	69,985	$ 28,527.91	$ 112.79	$ 104.43	$ -	$ -
TN	366	159	445,750	$ 371,925.11	$ 12,158.31	$ 24,220.80	$ -	$ -
TN	371	86	2,152,666	$ 500,029.82	$ -	$ 33,666.23	$ -	$ -
TN	372	53	4,763,502	$ 278,379.60	$ -	$ 18,823.15	$ -	$ -
TN	373	2	378,515	$ 54,052.84	$ -	$ -	$ -	$ -
TN	381	2	1,486	$ 4,455.20	$ -	$ -	$ -	$ -
TN Totals		**164,908**	**11,605,929**	**$ 6,288,398.96**	**$ 140,949.59**	**$ 349,382.68**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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October 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		38		$ 190.61	$ -	$ -	$ -	$ -
TN	311	49,894	1,405,385	$ 1,593,164.15	$ -	$ 73,888.88	$ -	$ -
TN	313	98,773	1,033,065	$ 1,821,835.87	$ -	$ 98,708.31	$ -	$ -
TN	321	12,098	367,407	$ 659,488.96	$ 38,063.29	$ 39,077.34	$ -	$ -
TN	331	41	377,813	$ 323,149.23	$ 9,269.30	$ 20,135.42	$ -	$ -
TN	332	3,647	1,485,018	$ 1,310,481.25	$ 86,922.72	$ 76,468.49	$ -	$ -
TN	341	2	9,087	$ 5,964.60	$ 424.01	$ 413.35	$ -	$ -
TN	352	341	237,311	$ 218,097.46	$ 9,566.61	$ 12,891.43	$ -	$ -
TN	362	1	1,778	$ 672.97	$ -	$ -	$ -	$ -
TN	365	8	199,538	$ 81,525.45	$ -	$ -	$ -	$ -
TN	366	145	499,235	$ 415,192.82	$ 15,854.88	$ 26,896.06	$ -	$ -
TN	371	86	2,606,991	$ 530,949.79	$ -	$ 35,777.07	$ -	$ -
TN	372	53	5,122,713	$ 298,659.23	$ -	$ 20,172.87	$ -	$ -
TN	373	2	523,420	$ 59,120.14	$ -	$ -	$ -	$ -
TN	381	2	4,117	$ 5,897.75	$ -	$ -	$ -	$ -
TN Totals		**165,131**	**13,872,878**	**$ 7,324,390.28**	**$ 160,100.81**	**$ 404,429.22**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

November 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		29		$ 293.74	$ -	$ -	$ -	$ -
TN	311	47,490	3,012,408	$ 3,021,255.83	$ 4.35	$ 137,308.59	$ -	$ -
TN	313	102,466	3,753,117	$ 4,446,590.51	$ 17.34	$ 237,495.16	$ -	$ -
TN	321	12,628	1,285,231	$ 1,477,411.47	$ 80,615.44	$ 87,980.47	$ -	$ -
TN	331	41	495,903	$ 380,079.17	$ 11,592.86	$ 22,813.89	$ -	$ -
TN	332	3,676	1,690,570	$ 1,528,896.86	$ 100,359.88	$ 89,009.27	$ -	$ -
TN	341	2	14,573	$ 8,951.79	$ 647.60	$ 620.36	$ -	$ -
TN	352	342	656,537	$ 578,142.34	$ 24,811.17	$ 34,583.54	$ -	$ -
TN	360	1	627,430	$ 208,985.45	$ -	$ -	$ -	$ -
TN	362	1	1,376	$ 487.38	$ -	$ -	$ -	$ -
TN	365	19	330,045	$ 143,011.39	$ 10.65	$ 9.86	$ -	$ -
TN	366	144	600,258	$ 515,174.12	$ 19,831.29	$ 33,075.08	$ -	$ -
TN	371	86	2,952,857	$ 559,257.88	$ -	$ 37,687.77	$ -	$ -
TN	372	53	6,044,795	$ 326,173.80	$ -	$ 22,041.12	$ -	$ -
TN	373	2	642,319	$ 63,254.37	$ -	$ -	$ -	$ -
TN	381	2	8,177	$ 7,981.67	$ -	$ -	$ -	$ -
TN Totals		**166,982**	**22,115,596**	**$ 13,265,947.77**	**$ 237,890.58**	**$ 702,625.11**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

December 2011 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		27		$ 119.19	$ -	$ -	$ -	$ -
TN	311	47786	5,454,082	$ 5,200,506.87	$ -	$ 237,887.63	$ -	$ -
TN	313	103753	7,766,226	$ 8,133,080.50	$ 36.39	$ 435,691.98	$ -	$ -
TN	321	12704	3,199,872	$ 3,287,682.78	$ 180,146.70	$ 196,802.01	$ -	$ -
TN	331	41	754,847	$ 519,171.85	$ 16,836.37	$ 30,881.82	$ -	$ -
TN	332	3725	2,076,764	$ 1,888,153.60	$ 123,219.02	$ 110,530.17	$ -	$ -
TN	341	2	20,311	$ 12,110.11	$ 884.00	$ 839.23	$ -	$ -
TN	352	351	1,390,122	$ 1,241,805.47	$ 52,911.72	$ 73,739.39	$ -	$ -
TN	360	1	3,152,700	$ 1,037,238.30	$ -	$ -	$ -	$ -
TN	362	1	1,085	$ 367.92	$ -	$ -	$ -	$ -
TN	365	28	68,461	$ 22,106.06	$ 3.55	$ 3.29	$ -	$ -
TN	366	149	755,322	$ 656,692.29	$ 26,116.85	$ 41,915.80	$ -	$ -
TN	371	86	3,437,735	$ 597,148.11	$ -	$ 40,238.58	$ -	$ -
TN	372	53	6,582,113	$ 350,820.42	$ -	$ 23,682.63	$ -	$ -
TN	373	2	783,518	$ 68,176.76	$ -	$ -	$ -	$ -
TN	381	2	14,326	$ 11,246.91	$ -	$ -	$ -	$ -
TN Totals		**168,711**	**35,457,484**	**$ 23,026,427.14**	**$ 400,154.60**	**$ 1,192,212.53**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

January 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		30		$ 297.16	$ -	$ -	$ -	$ -
TN	311	47,948	7,999,073	$ 7,586,131.97	$ 23.86	$ 340,606.37	$ -	$ -
TN	313	104,209	11,896,203	$ 12,126,909.94	$ -	$ 642,082.45	$ -	$ -
TN	321	12,882	5,066,149	$ 5,211,531.81	$ 283,357.68	$ 307,755.07	$ -	$ -
TN	331	41	793,453	$ 539,720.42	$ 17,616.32	$ 32,291.21	$ -	$ -
TN	332	3,740	2,526,700	$ 2,324,827.56	$ 151,110.25	$ 134,349.48	$ -	$ -
TN	341	2	24,620	$ 14,474.03	$ 1,060.95	$ 1,003.05	$ -	$ -
TN	352	362	1,974,604	$ 1,832,229.87	$ 79,048.97	$ 106,526.83	$ -	$ -
TN	360	3	1,119,400	$ 316,014.10	$ -	$ -	$ -	$ -
TN	362	1	620	$ 193.07	$ -	$ -	$ -	$ -
TN	365	7	71,126	$ 26,802.52	$ 7.88	$ 7.29	$ -	$ -
TN	366	144	912,328	$ 806,641.10	$ 32,014.48	$ 50,885.94	$ -	$ -
TN	371	90	2,106,388	$ 460,386.64	$ -	$ 30,743.32	$ -	$ -
TN	372	54	8,550,755	$ 405,708.91	$ -	$ 27,473.08	$ -	$ -
TN	373	2	789,537	$ 68,356.13	$ -	$ -	$ -	$ -
TN	381	2	16,473	$ 12,387.01	$ -	$ -	$ -	$ -
TN Totals		**169,517**	**43,847,429**	**$ 31,732,612.24**	**$ 564,240.39**	**$ 1,673,724.09**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No.

February 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		39		$ 313.30	$ -	$ -	$ -	$ -
TN	311	48,193	6,944,595	$ 5,854,800.80	$ 19.62	$ 257,379.11	$ -	$ -
TN	313	104,809	10,275,099	$ 9,494,036.96	$ 5.00	$ 493,572.60	$ -	$ -
TN	321	12,986	4,372,713	$ 4,025,243.87	$ 218,252.57	$ 236,486.17	$ -	$ -
TN	328	1	10,186	$ 2,806.24	$ 210.05	$ 194.47	$ -	$ -
TN	331	41	778,978	$ 424,787.85	$ 13,257.30	$ 25,647.51	$ -	$ -
TN	332	3,737	2,277,127	$ 1,805,603.15	$ 116,762.64	$ 104,346.10	$ -	$ -
TN	341	2	20,899	$ 9,589.80	$ 695.36	$ 664.57	$ -	$ -
TN	352	361	1,674,696	$ 1,344,168.14	$ 56,787.46	$ 79,425.44	$ -	$ -
TN	360	5	335,200	$ 84,344.70	$ -	$ -	$ -	$ -
TN	362	1	514	$ 137.91	$ -	$ -	$ -	$ -
TN	365	11	16	$ 4.11	$ 0.31	$ 0.28	$ -	$ -
TN	366	157	832,402	$ 628,500.02	$ 22,663.57	$ 39,791.83	$ -	$ -
TN	371	94	1,913,693	$ 443,171.80	$ -	$ 29,597.81	$ -	$ -
TN	372	54	7,908,928	$ 381,945.37	$ -	$ 25,889.01	$ -	$ -
TN	373	2	678,382	$ 64,458.56	$ -	$ -	$ -	$ -
TN	381	2	13,760	$ 9,074.58	$ -	$ -	$ -	$ -
TN Totals		**170,495**	**38,037,188**	**$ 24,572,987.16**	**$ 428,653.88**	**$ 1,292,994.90**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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March 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		36		$ 399.89	$ -	$ -	$ -	$ -
TN	301	152,843	12,897,378	$ 12,830,699.77	$ 133.74	$ 636,217.84	$ -	$ -
TN	302	16,574	4,966,347	$ 4,849,909.37	$ 285,122.45	$ 285,506.26	$ -	$ -
TN	311	111	19	$ 79.14	$ -	$ 12.15	$ -	$ -
TN	313	314	516	$ 810.86	$ 17.74	$ 27.36	$ -	$ -
TN	321	30	913	$ 842.56	$ (95.25)	$ 58.40	$ -	$ -
TN	331	43	449,204	$ 310,986.99	$ 9,204.41	$ 19,083.49	$ -	$ -
TN	332	6	-31	$ (41.53)	$ (3.11)	$ (2.88)	$ -	$ -
TN	341	1	8,762	$ 4,312.51	$ 322.80	$ 298.86	$ -	$ -
TN	342		3,056	$ 3,368.83			$ -	$ -
TN	352	493	1,889,994	$ 1,671,077.88	$ 66,920.48	$ 102,731.52	$ -	$ -
TN	360	2		$ -	$ -	$ -	$ -	$ -
TN	362	2	2,723	$ 680.75	$ 26.76	$ 24.77	$ -	$ -
TN	365	7	144	$ 31.52	$ 2.36	$ 2.18	$ -	$ -
TN	371	84	1,416,645	$ 430,759.57	$ -	$ 28,735.47	$ -	$ -
TN	372	52	6,770,926	$ 358,299.44	$ -	$ 24,242.47	$ -	$ -
TN	373	2	511,483	$ 59,162.44	$ -	$ -	$ -	$ -
		4	4,964	$ 5,595.62	$ -	$ -	$ -	$ -
TN Totals		**170,604**	**28,923,043**	**$ 20,526,975.61**	**$ 361,652.38**	**$ 1,096,937.89**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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April 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		41		$ 446.35	$ -	$ -	$ -	$ -
TN	221	9	(372)	$ (339.89)	$ (17.74)	$ -	$ -	$ -
TN	301	151,972	4,014,459	$ 6,304,578.77	$ -	$ 308,423.21	$ -	$ -
TN	302	16,426	2,334,846	$ 2,897,434.80	$ 180,939.55	$ 169,132.85	$ -	$ -
TN	311	51	2,575	$ 2,149.28	$ -	$ 143.92	$ -	$ -
TN	313	250	3,486	$ 2,757.15	$ 12.46	$ 79.53	$ -	$ -
TN	321	28	3,662	$ 3,117.07	$ 233.34	$ 216.01	$ -	$ -
TN	331	41	354,130	$ 273,550.85	$ 7,799.09	$ 16,834.60	$ -	$ -
TN	332	4	40	$ 29.08	$ 2.18	$ 2.02	$ -	$ -
TN	341	1	10,806	$ 5,131.91	$ 384.13	$ 355.64	$ -	$ -
TN	342	1	3,112	$ 3,430.34	$ -	$ -	$ -	$ -
TN	352	504	949,721	$ 1,003,146.68	$ 40,189.92	$ 62,545.05	$ -	$ -
TN	362	2	1,600	$ 348.16	$ 6.69	$ 6.20	$ -	$ -
TN	365	15	39,194	$ 8,047.43	$ 36.06	$ 152.53	$ -	$ -
TN	371	86	1,290,324	$ 418,559.75	$ -	$ 27,907.48	$ -	$ -
TN	372	52	6,152,725	$ 339,956.77	$ -	$ 23,002.78	$ -	$ -
TN	373	2	439,357	$ 56,631.60	$ -	$ -	$ -	$ -
		2	3,549	$ 5,038.04	$ -	$ -	$ -	$ -
TN Totals		**169,487**	**15,603,214**	**$ 11,324,014.14**	**$ 229,585.68**	**$ 608,801.82**	**$ -**	**$ -**

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May 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		31		$ 406.43	$ -	$ -	$ -	$ -
TN	301	151,842	3,369,028	$ 4,199,207.26	$ -	$ 200,221.04	$ -	$ -
TN	302	16,163	1,989,227	$ 2,042,953.95	$ 129,795.32	$ 114,275.76	$ -	$ -
TN	311	6	(374)	$ (302.39)	$ -	$ (20.95)	$ -	$ -
TN	313	56	(173)	$ (358.81)	$ -	$ (33.13)	$ -	$ -
TN	321	30	323	$ 16.47	$ 1.21	$ 1.14	$ -	$ -
TN	328	1	186,934	$ 45,051.09	$ -	$ 3,122.01	$ -	$ -
TN	331	41	275,305	$ 242,499.08	$ 6,876.45	$ 14,357.49	$ -	$ -
TN	341	1	1,514	$ 1,406.93	$ 105.01	$ 93.14	$ -	$ -
TN	342		4,986	$ 5,496.27				
TN	352	495	790,596	$ 641,225.79	$ 24,630.91	$ 38,170.93	$ -	$ -
TN	362	2	640	$ 129.79	$ 1.51	$ 1.34	$ -	$ -
TN	365	18	36,142	$ 9,945.03	$ 6.88	$ 6.11	$ -	$ -
TN	371	84	1,359,656	$ 424,261.68	$ -	$ 25,545.88	$ -	$ -
TN	372	52	5,242,313	$ 314,437.40	$ -	$ 20,346.62	$ -	$ -
TN	373	2	383,661	$ 54,642.12	$ -	$ -	$ -	$ -
TN	381	2	2,032	$ 4,440.25	$ -	$ -	$ -	$ -
TN Totals		**168,826**	**13,641,810**	**$ 7,985,458.34**	**$ 161,417.29**	**$ 416,087.38**	**$ -**	**$ -**

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June 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN	301	150,892	2,068,527	$ 3,352,670.01	$ 2.15	$ 161,721.16	$ -	$ -
TN	302	15,913	1,734,196	$ 1,861,095.27	$ 121,619.05	$ 105,191.84	$ -	$ -
TN	311	18	86	$ 72.36	$ -	$ -	$ -	$ -
TN	313	66	1,841	$ 1,549.53	$ -	$ 42.03	$ -	$ -
TN	321	32	863	$ 767.22	$ 55.52	$ 25.95	$ -	$ -
TN	328	3	-	$ -	$ -	$ -	$ -	$ -
TN	331	40	188,217	$ 185,828.46	$ 5,329.24	$ 11,165.74	$ -	$ -
TN	332	6	423	$ 361.56	$ 27.06	$ 25.05	$ -	$ -
TN	341	1	-	$ 800.00	$ 59.71	$ 52.96	$ -	$ -
TN	342		5,844	$ 6,443.01				
TN	352	496	615,395	$ 523,851.56	$ 21,540.51	$ 31,135.50	$ -	$ -
TN	362	2	450	$ 111.29	$ 1.66	$ 1.47	$ -	$ -
TN	365	1	1,507	$ 365.45	$ 5.84	$ 24.19	$ -	$ -
TN	371	89	1,069,138	$ 384,931.98	$ -	$ 24,411.37	$ -	$ -
TN	372	52	5,384,872	$ 315,285.84	$ -	$ 20,420.61	$ -	$ -
TN	373	2	372,947	$ 54,256.01	$ -	$ -	$ -	$ -
TN	381	2	1,583	$ 4,263.32	$ -	$ -	$ -	$ -
TN Totals		**167,615**	**11,445,889**	**$ 6,692,652.87**	**$ 148,640.74**	**$ 354,217.87**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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July 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		31		$ 285.24	$ -	$ -	$ -	$ -
TN	301	150,466	1,648,480	$ 3,077,381.32	$ 2.20	$ 148,299.68	$ -	$ -
TN	302	15,783	1,526,713	$ 1,713,509.63	$ 112,504.11	$ 96,149.29	$ -	$ -
TN	311	1	2	$ 14.25	$ -	$ 0.94	$ -	$ -
TN	313	12	239	$ 203.57	$ -	$ 14.12	$ -	$ -
TN	321	58	3,553	$ 3,068.34	$ 77.48	$ 220.68	$ -	$ -
TN	331	40	181,847	$ 183,327.06	$ 5,305.84	$ 11,001.03	$ -	$ -
TN	341	2	3,645	$ 3,061.21	$ 225.91	$ 166.02	$ -	$ -
TN	342		10,036	$ 11,063.90				
TN	352	499	488,102	$ 438,475.15	$ 18,831.00	$ 25,882.14	$ -	$ -
TN	360	1	388,000	$ 117,093.00	$ -	$ -	$ -	$ -
TN	362	1	598	$ 165.59	$ -	$ -	$ -	$ -
TN	365	15	45,246	$ 14,419.47	$ 4.78	$ -	$ -	$ -
TN	371	88	1,031,481	$ 381,179.58	$ -	$ 24,178.76	$ -	$ -
TN	372	52	5,217,991	$ 305,956.03	$ -	$ 19,821.48	$ -	$ -
TN	373	2	334,547	$ 52,926.72	$ -	$ -	$ -	$ -
TN	381	2	1,438	$ 4,206.18	$ -	$ -	$ -	$ -
TN Totals		**167,053**	**10,881,918**	**$ 6,306,336.24**	**$ 136,951.32**	**$ 325,734.14**	**$ -**	**$ -**

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August 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		35		$ 220.25	$ -	$ -	$ -	$ -
TN	301	150,544	1,485,772	$ 2,972,295.01	$ (46.47)	$ 144,101.64	$ -	$ -
TN	302	15,654	1,491,500	$ 1,686,689.99	$ 110,604.07	$ 95,135.12	$ -	$ -
TN	311	19	146	$ 105.50	$ -	$ 5.81	$ -	$ -
TN	313	21	254	$ 198.92	$ -	$ 17.94	$ -	$ -
TN	321	7	(17)	$ (218.56)	$ (16.36)	$ (15.15)	$ -	$ -
TN	328	2		$ 32,210.48	$ -	$ 2,232.22	$ -	$ -
TN	331	40	209,603	$ 194,224.35	$ 5,443.66	$ 11,717.01	$ -	$ -
TN	341	2	6,088	$ 4,040.56	$ 110.75	$ 214.99	$ -	$ -
TN	342		10,472	$ 11,544.58				
TN	352	497	532,113	$ 468,598.40	$ 18,878.51	$ 28,137.22	$ -	$ -
TN	360	1	62,000	$ 19,685.00	$ -	$ -	$ -	$ -
TN	362	1	560	$ 171.75	$ -	$ -	$ -	$ -
TN	365	21	1,181	$ 359.01	$ 7.24	$ 5.84	$ -	$ -
TN	371	92	1,073,595	$ 384,859.42	$ -	$ 26,021.88	$ -	$ -
TN	372	52	5,208,363	$ 310,157.21	$ -	$ 20,104.96	$ -	$ -
TN	373	2	379,548	$ 54,499.40	$ -	$ -	$ -	$ -
TN	381	2	1,692	$ 4,306.27	$ -	$ -	$ -	$ -
TN total		**166,992**	**10,462,870**	**$ 6,143,947.54**	**$ 134,981.40**	**$ 327,679.48**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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September 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN	301	150,239	1,757,734	$ 3,143,518.14	$ 22.65	$ 151,972.66	$ -	$ -
TN	302	15,604	1,634,916	$ 1,778,867.99	$ 115,207.07	$ 100,481.52	$ -	$ -
TN	311	8	411	$ 437.96	$ 26.46	$ 29.57	$ -	$ -
TN	313	74	1,396	$ 1,143.63	$ -	$ 102.27	$ -	$ -
TN	321	18	460	$ 516.78	$ 38.69	$ 35.82	$ -	$ -
TN	331	40	214,319	$ 196,131.50	$ 5,534.73	$ 11,837.19	$ -	$ -
TN	341	2	2,749	$ 2,702.02	$ 154.56	$ 165.91	$ -	$ -
TN	342		10,268	$ 11,319.65	$ -	$ -	$ -	$ -
TN	352	507	517,655	$ 458,892.26	$ 20,452.64	$ 27,008.52	$ -	$ -
TN	360	1	552,000	$ 147,061.00	$ -	$ -	$ -	$ -
TN	362	1	1,595	$ 418.05	$ -	$ -	$ -	$ -
TN	365	4	54,106	$ 17,119.63	$ 20.21	$ 78.06	$ -	$ -
TN	371	85	1,122,824	$ 386,064.62	$ -	$ 24,528.04	$ -	$ -
TN	372	52	5,263,160	$ 310,096.31	$ -	$ 20,077.71	$ -	$ -
TN	373	2	350,766	$ 53,556.02	$ -	$ -	$ -	$ -
TN	381	2	1,898	$ 4,387.45	$ -	$ -	$ -	$ -
TN		**166,639**	**11,486,257**	**$ 6,512,233.01**	**$ 141,457.01**	**$ 336,317.27**	**$ -**	**$ -**

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October 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		30		$ 284.51	$ -	$ -	$ -	$ -
TN	301	150,738	2,408,081	$ 3,611,719.62	$ 4.32	$ 175,890.66	$ -	$ -
TN	302	15,734	1,750,484	$ 1,914,171.19	$ 123,013.43	$ 108,335.72	$ -	$ -
TN	311	15	595	$ 562.62	$ -	$ 39.00	$ -	$ -
TN	313	12	678	$ 628.60	$ -	$ 43.56	$ -	$ -
TN	321	7	(541)	$ (681.75)	$ (51.04)	$ (47.26)	$ -	$ -
TN	331	40	332,311	$ 257,672.81	$ 7,970.89	$ 15,351.73	$ -	$ -
TN	341	2	17,683	$ 8,669.20	$ 599.91	$ 560.94	$ -	$ -
TN	342		9,999	$ 11,452.75				
TN	352	496	677,970	$ 585,764.72	$ 24,585.10	$ 34,332.08	$ -	$ -
TN	362	1	2,158	$ 643.08	$ -	$ -	$ -	$ -
TN	365	78	102,977	$ 45,586.67	$ 567.61	$ 587.79	$ -	$ -
TN	371	85	1,577,047	$ 464,421.92	$ -	$ 29,456.99	$ -	$ -
TN	372	52	6,645,437	$ 363,857.65	$ -	$ 23,558.14	$ -	$ -
TN	373	2	461,948	$ 64,197.59	$ -	$ -	$ -	$ -
TN	381	2	5,575	$ 6,507.95	$ -	$ -	$ -	$ -
TN Totals		**167,294**	**13,992,402**	**$ 7,335,459.13**	**$ 156,690.22**	**$ 388,109.35**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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November 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		44		$ 257.34	$ -	$ -	$ -	$ -
TN	301	152,046	8,934,170	$ 8,583,721.42	$ 12.28	$ 420,017.02	$ -	$ -
TN	302	16,139	3,843,366	$ 3,402,191.59	$ 208,954.90	$ 193,552.43	$ -	$ -
TN	311	1	78	$ 60.59	$ -	$ -	$ -	$ -
TN	313	10	241	$ 206.67	$ -	$ 7.21	$ -	$ -
TN	321	33	496	$ 133.82	$ 10.02	$ 9.27	$ -	$ -
TN	331	41	576,189	$ 338,962.98	$ 11,685.15	$ 19,298.72	$ -	$ -
TN	332	10	371	$ 309.49	$ 22.76	$ 15.49	$ -	$ -
TN	341	2	24,754	$ 10,581.18	$ 742.61	$ 687.51	$ -	$ -
TN	342		7,830	$ 8,823.71				
TN	352	495	1,612,449	$ 1,243,197.53	$ 52,243.19	$ 71,752.35	$ -	$ -
TN	362	1	2,075	$ 715.46	$ -	$ -	$ -	$ -
TN	365	24	87,806	$ 35,730.29	$ 158.47	$ 6.85	$ -	$ -
TN	371	88	1,991,374	$ 510,002.62	$ -	$ 32,391.23	$ -	$ -
TN	372	53	7,610,241	$ 393,170.28	$ -	$ 25,437.52	$ -	$ -
TN	373	2	602,424	$ 70,102.72	$ -	$ -	$ -	$ -
TN	381	2	12,549	$ 8,912.42	$ -	$ -	$ -	$ -
TN Totals		**168,991**	**25,306,413**	**$ 14,607,080.11**	**$ 273,829.38**	**$ 763,175.60**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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December 2012 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		29		$ 160.80	$ -	$ -	$ -	$ -
TN	301	153,030	12,878,298	$ 12,611,027.74	$ 21.88	$ 607,631.51	$ -	$ -
TN	302	16,382	5,043,599	$ 4,829,301.22	$ 287,499.71	$ 273,143.55	$ -	$ -
TN	311	1	81	$ 65.61	$ -	$ -	$ -	$ -
TN	313	6	128	$ 109.19	$ -	$ 5.47	$ -	$ -
TN	331	41	675,512	$ 374,889.92	$ 13,496.82	$ 21,474.33	$ -	$ -
TN	341	2	27,341	$ 11,508.36	$ 811.81	$ 748.89	$ -	$ -
TN	342		11,414	$ 12,862.55	$ -	$ -	$ -	$ -
TN	352	502	1,939,629	$ 1,699,343.54	$ 68,849.26	$ 98,993.52	$ -	$ -
TN	362	1	1,947	$ 723.70	$ -	$ -	$ -	$ -
TN	365	25	116,453	$ 46,126.42	$ 35.28	$ 31.30	$ -	$ -
TN	371	86	2,014,216	$ 513,314.54	$ -	$ 32,589.73	$ -	$ -
TN	372	55	8,213,735	$ 408,158.27	$ -	$ 26,413.71	$ -	$ -
TN	373	2	598,644	$ 69,962.51	$ -	$ -	$ -	$ -
TN	381	2	16,745	$ 10,418.24	$ -	$ -	$ -	$ -
TN Totals		**170,164**	**31,537,742**	**$ 20,587,972.61**	**$ 370,714.76**	**$ 1,061,032.01**	**$ -**	**$ -**

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January 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		26		$ 297.81	$ -	$ -	$ -	$ -
TN	301	154,170	20,645,646	$ 18,296,003.90	$ 34.73	$ 875,838.49	$ -	$ -
TN	302	16,692	8,261,609	$ 7,226,045.51	$ 425,683.31	$ 409,121.33	$ -	$ -
TN	311	4	185	$ 152.05	$ -	$ 10.53	$ -	$ -
TN	313	23	720	$ 623.15	$ -	$ 37.80	$ -	$ -
TN	331	41	859,429	$ 441,252.08	$ 16,312.71	$ 24,973.30	$ -	$ -
TN	341	2	33,629	$ 13,761.98	$ 980.01	$ 898.08	$ -	$ -
TN	342	-	10,933	$ 12,320.51		$ -	$ -	$ -
TN	352	498	2,984,825	$ 2,448,561.79	$ 102,102.67	$ 141,167.42	$ -	$ -
TN	362	1	1,079	$ 365.24	$ -	$ -	$ -	$ -
TN	365	22	34,315	$ 12,797.63	$ 160.68	$ 665.11	$ -	$ -
TN	371	86	2,361,773	$ 541,589.40	$ -	$ 34,362.42	$ -	$ -
TN	372	51	9,225,324	$ 437,288.84	$ -	$ 28,259.64	$ -	$ -
TN	373	2	708,912	$ 73,768.23	$ -	$ -	$ -	$ -
TN	381	2	22,922	$ 12,634.98	$ -	$ -	$ -	$ -
TN total		**171,620**	**45,151,301**	**$ 29,517,463.10**	**$ 545,274.11**	**$ 1,515,334.12**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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CAD Data Request No. 1, Item 14 Attachment 2 of 2

February 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		39		$ 345.04	$ -	$ -	$ -	$ -
TN	301	154,212	21,056,944	$ 18,738,744.95	$ 32.31	$ 891,067.67	$ -	$ -
TN	302	16,659	8,033,476	$ 7,089,970.62	$ 414,454.97	$ 397,928.06	$ -	$ -
TN	311	7	14	$ (2.46)	$ -	$ 1.56	$ -	$ -
TN	313	7	22	$ 23.07	$ -	$ 2.29	$ -	$ -
TN	331	41	760,949	$ 405,831.42	$ 15,041.48	$ 23,062.94	$ -	$ -
TN	341	2	26,956	$ 11,370.38	$ 801.51	$ 739.76	$ -	$ -
TN	342	-	9,574	$ 10,789.04		$ -	$ -	$ -
TN	352	499	2,785,581	$ 2,322,808.41	$ 98,830.86	$ 133,461.91	$ -	$ -
TN	362	1	1,073	$ 348.73	$ -	$ -	$ -	$ -
TN	365	23	107,325	$ 40,645.57	$ (56.03)	$ 3.69	$ -	$ -
TN	371	86	2,064,491	$ 517,929.95	$ -	$ 32,858.24	$ -	$ -
TN	372	53	8,281,171	$ 405,716.42	$ -	$ 26,239.38	$ -	$ -
TN	373	2	634,015	$ 71,146.46	$ -	$ -	$ -	$ -
TN	381	2	19,713	$ 11,483.36	$ -	$ -	$ -	$ -
TN total		**171,633**	**43,781,304**	**$ 29,627,150.96**	**$ 529,105.10**	**$ 1,505,365.50**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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March 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		42		$ 477.51	$ -	$ -	$ -	$ -
TN	301	154,431	18,644,216	$ 15,416,114.66	$ 104.89	$ 728,456.69	$ -	$ -
TN	302	16,728	7,251,613	$ 5,885,369.39	$ 346,945.47	$ 331,352.83	$ -	$ -
TN	311	11	569	$ 419.99	$ -	$ (7.60)	$ -	$ -
TN	313	8	179	$ 144.38	$ -	$ 2.86	$ -	$ -
TN	331	41	783,011	$ 413,721.38	$ 15,208.35	$ 23,577.34	$ -	$ -
TN	341	2	27,750	$ 11,654.95	$ 822.75	$ 758.60	$ -	$ -
TN	342		8,626	$ 9,720.73	$ -	$ -	$ -	$ -
TN	352	503	2,638,210	$ 1,975,594.32	$ 84,688.42	$ 114,329.80	$ -	$ -
TN	360	1	1,794,330	$ 674,843.73	$ -	$ -	$ -	$ -
TN	365	23	56,187	$ 26,342.67	$ 54.55	$ 225.79	$ -	$ -
TN	371	86	2,215,175	$ 530,177.72	$ -	$ 32,766.71	$ -	$ -
TN	372	51	8,557,984	$ 418,426.57	$ -	$ 27,058.76	$ -	$ -
TN	373	2	694,012	$ 73,180.02	$ -	$ -	$ -	$ -
TN	381	2	19,621	$ 11,450.35	$ -	$ -	$ -	$ -
TN Totals		**171,931**	**42,691,483**	**$ 25,447,638.37**	**$ 447,824.43**	**$ 1,258,521.78**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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April 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		46		$ 408.17	$ -	$ -	$ -	$ -
TN	301	154,581	13,474,102	$ 10,176,301.35	$ 28.87	$ 474,571.06	$ -	$ -
TN	302	16,668	5,282,223	$ 4,104,334.38	$ 244,155.50	$ 229,072.33	$ -	$ -
TN	311	1	175	$ 118.32	$ -	$ 7.83	$ -	$ -
TN	313	2	58	$ 58.15	$ -	$ 1.96	$ -	$ -
TN	321	10	(349)	$ (593.64)	$ (44.43)	$ (41.15)	$ -	$ -
TN	331	41	381,072	$ 267,929.61	$ 8,657.96	$ 15,826.18	$ -	$ -
TN	341	2	20,123	$ 8,958.78	$ 442.00	$ 530.72	$ -	$ -
TN	342		8,718	$ 9,824.40				
TN	352	512	1,885,042	$ 1,313,791.45	$ 54,727.35	$ 76,933.29	$ -	$ -
TN	360	3	7,242,470	$ 2,982,599.19	$ -	$ -	$ -	$ -
TN	365	21	30,854	$ 13,896.64	$ 51.54	$ 213.34	$ -	$ -
TN	371	86	1,575,177	$ 474,777.13	$ -	$ 30,133.31	$ -	$ -
TN	372	51	7,080,310	$ 375,783.96	$ -	$ 24,324.16	$ -	$ -
TN	373	2	519,394	$ 67,068.39	$ -	$ -	$ -	$ -
TN	381	2	6,320	$ 6,677.02	$ -	$ -	$ -	$ -
TN Totals		**172,028**	**37,505,689**	**$ 19,801,933.30**	**$ 308,018.79**	**$ 851,573.03**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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May 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		50		$ 424.08	$ -	$ -	$ -	$ -
TN	301	154,556	4,999,999	$ 5,404,034.71	$ 15.25	$ 257,347.84	$ -	$ -
TN	302	16,464	2,627,808	$ 2,549,320.38	$ 160,338.02	$ 144,624.99	$ -	$ -
TN	311	1	7	$ 17.38	$ -	$ 0.87	$ -	$ -
TN	321	1	9	$ 35.21	$ 2.63	$ 2.36	$ -	$ -
TN	331	41	248,881	$ 219,874.77	$ 6,881.06	$ 13,251.95	$ -	$ -
TN	341	2	14,415	$ 6,871.42	$ 260.93	$ 387.36	$ -	$ -
TN	342		11,091	$ 12,498.56				
TN	352	501	974,473	$ 788,841.92	$ 32,216.41	$ 47,074.79	$ -	$ -
TN	360	1	791,000	$ 324,780.00	$ -	$ -	$ -	$ -
TN	365	21	28,409	$ 12,454.51	$ 31.06	$ 129.84	$ -	$ -
TN	371	86	1,339,127	$ 452,949.80	$ -	$ 29,034.51	$ -	$ -
TN	372	51	6,192,538	$ 342,094.09	$ -	$ 22,362.44	$ -	$ -
TN	373	3	440,631	$ 19,422.09	$ -	$ -	$ -	$ -
TN	381	2	3,350	$ 5,611.17	$ -	$ -	$ -	$ -
TN Total		**171,780**	**17,671,738**	**$ 10,139,230.09**	**$ 199,745.36**	**$ 514,216.95**	**$ -**	**$ -**

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June 2013 301-C including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		58		$ 822.22	$ -	$ -	$ -	$ -
TN	301	153,820	2,606,619	$ 3,800,003.11	$ 16.93	$ 182,269.08	$ -	$ -
TN	302	16,250	1,921,813	$ 2,046,348.33	$ 132,020.56	$ 116,034.92	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.87	$ -	$ -
TN	331	44	237,714	$ 226,589.88	$ 7,624.45	$ 13,842.69	$ -	$ -
TN	341	2		$ 1,600.00	$ 72.35	$ 93.52	$ -	$ -
TN	342		9,685	$ 10,914.12	$ -	$ -	$ -	$ -
TN	352	439	602,494	$ 516,104.39	$ 22,244.37	$ 30,931.51	$ -	$ -
TN	360	1	2,370,000	$ 971,700.00	$ -	$ -	$ -	$ -
TN	365	20	44,608	$ 20,705.25	$ -	$ -	$ -	$ -
TN	371	82	1,108,679	$ 424,405.45	$ -	$ 27,150.92	$ -	$ -
TN	372	51	5,321,145	$ 309,340.23	$ -	$ 20,215.38	$ -	$ -
TN	373	1	399,427	$ 17,979.95	$ -	$ -	$ -	$ -
TN	381	2	2,081	$ 5,155.77	$ -	$ -	$ -	$ -
TN Total		**170,771**	**14,624,265**	**$ 8,351,681.70**	**$ 161,978.66**	**$ 390,538.89**	**$ -**	**$ -**

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July 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		30		$ 392.00	$ -	$ -	$ -	$ -
TN	301	153,943	1,725,601	$ 3,213,084.33	$ 10.05	$ 156,584.60	$ -	$ -
TN	302	16,137	1,606,588	$ 1,818,635.98	$ 118,531.72	$ 103,810.61	$ -	$ -
TN	311	3	10	$ 45.26	$ -	$ 1.08	$ -	$ -
TN	313	2	1	$ 0.66	$ -	$ 0.01	$ -	$ -
TN	331	44	234,640	$ 225,550.60	$ 7,785.90	$ 13,774.60	$ -	$ -
TN	341	2		$ 1,889.00	$ 72.35	$ 93.52	$ -	$ -
TN	342		10,633	$ 11,982.43	$ -	$ -	$ -	$ -
TN	352	436	460,847	$ 416,036.04	$ 17,908.73	$ 24,880.14	$ -	$ -
TN	365	20	185,715	$ 84,851.49	$ 47.13	$ 197.02	$ -	$ -
TN	371	82	1,092,800	$ 423,691.22	$ -	$ 27,111.39	$ -	$ -
TN	372	51	5,495,075	$ 317,510.56	$ -	$ 20,762.04	$ -	$ -
TN	373	1	357,500	$ 16,512.50	$ -	$ -	$ -	$ -
TN	381	2	1,991	$ 5,123.47	$ -	$ -	$ -	$ -
TN Totals		**170,753**	**11,171,401**	**$ 6,535,305.54**	**$ 144,355.88**	**$ 347,215.01**	**$ -**	**$ -**

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August 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		36		$ 498.75	$ -	$ -	$ -	$ -
TN	301	153,573	1,786,779	$ 3,249,299.73	$ (86.32)	$ 158,222.90	$ -	$ -
TN	302	15,903	1,703,672	$ 1,882,542.72	$ 122,967.97	$ 107,420.53	$ -	$ -
TN	331	44	257,279	$ 233,708.18	$ 8,004.95	$ 14,320.39	$ -	$ -
TN	341	2	2,666	$ 2,574.93	$ 87.71	$ 142.27	$ -	$ -
TN	342		11,286	$ 12,718.31	$ -	$ -	$ -	$ -
TN	352	456	526,461	$ 462,937.83	$ 18,585.75	$ 27,848.09	$ -	$ -
TN	360	1	4,025,000	$ 1,368,440.00	$ -	$ -	$ -	$ -
TN	365	24	3,314	$ (3,527.85)	$ 55.19	$ 230.72	$ -	$ -
TN	371	82	1,108,969	$ 423,207.31	$ -	$ 27,081.39	$ -	$ -
TN	372	51	5,617,434	$ 325,184.42	$ -	$ 21,274.63	$ -	$ -
TN	373	1	407,686	$ 18,269.01	$ -	$ -	$ -	$ -
TN	381	2	2,241	$ 5,213.19	$ -	$ -	$ -	$ -
TN Totals		**170,175**	**15,452,787**	**$ 7,981,066.53**	**$ 149,615.25**	**$ 356,540.92**	**$ -**	**$ -**

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September 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		31	0	$ 471.31	$ -	$ -	$ -	$ -
TN	301	153,037	1,771,007	$ 3,233,997.54	$ 10.88	$ 156,876.99	$ -	$ -
TN	302	15,841	1,661,355	$ 1,850,575.29	$ 119,473.98	$ 105,394.46	$ -	$ -
TN	311	1	2	$ 14.25	$ -	$ 0.71	$ -	$ -
TN	331	44	275,124	$ 240,051.25	$ 8,149.57	$ 14,731.98	$ -	$ -
TN	341	4	21,096	$ 9,278.13	$ 216.84	$ 484.18	$ -	$ -
TN	342		14,265	$ 16,075.37				
TN	352	456	512,644	$ 452,399.19	$ 18,723.69	$ 27,151.28	$ -	$ -
TN	360	1	2,970,000	$ 1,039,500.00	$ -	$ -	$ -	$ -
TN	365	19	63,069	$ 25,326.68	$ 103.45	$ 99.44	$ -	$ -
TN	371	82	1,135,770	$ 426,459.53	$ -	$ 27,297.28	$ -	$ -
TN	372	51	5,791,407	$ 329,254.34	$ -	$ 21,542.39	$ -	$ -
TN	373	1	419,684	$ 18,688.94	$ -	$ -	$ -	$ -
TN	381	2	2,629	$ 5,352.43	$ -	$ -	$ -	$ -
TN Total		**169,570**	**14,638,052**	**$ 7,647,444.25**	**$ 146,678.41**	**$ 353,578.71**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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October 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		36		$ 596.23	$ -	$ -	$ -	$ -
TN	301	153503	2,255,414	$ 3,877,168.03	$ 14.84	$ 188,992.24	$ -	$ -
TN	302	16042	1,962,743	$ 2,171,003.14	$ 139,075.96	$ 124,763.46	$ -	$ -
TN	311	3	18	$ 50.74	$ -	$ 3.02	$ -	$ -
TN	313	2		$ 26.00	$ -	$ 0.87	$ -	$ -
TN	331	45	432,665	$ 299,188.33	$ 10,865.96	$ 18,035.52	$ -	$ -
TN	341	2	31,142	$ 12,936.23	$ 444.80	$ 715.94	$ -	$ -
TN	342		17,255	$ 19,444.83				
TN	352	448	635,783	$ 572,385.64	$ 25,398.01	$ 34,222.20	$ -	$ -
TN	360	3	4,594,000	$ 1,587,355.00	$ -	$ -	$ -	$ -
TN	365	22	68,181	$ 30,444.86	$ 121.67	$ -	$ -	$ -
TN	371	82	1,544,158	$ 460,546.64	$ -	$ 29,469.36	$ -	$ -
TN	372	51	6,651,915	$ 365,137.60	$ -	$ 23,875.99	$ -	$ -
TN	373	1	515,947	$ 22,058.15	$ -	$ -	$ -	$ -
TN	381	2	6,012	$ 6,566.49	$ -	$ -	$ -	$ -
TN TOTALS		**170,242**	**18,715,233**	**$ 9,424,907.91**	**$ 175,921.24**	**$ 420,078.60**	**$ -**	**$ -**

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November 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		39		$ 544.07	$ -	$ -	$ -	$ -
TN	301	154549	8,529,533	$ 9,013,008.94	$ 25.21	$ 443,068.62	$ -	$ -
TN	302	16361	3,813,721	$ 3,677,304.80	$ 225,359.18	$ 211,287.82	$ -	$ -
TN	311	4	162	$ 158.46	$ -	$ 9.39	$ -	$ -
TN	313	4	113	$ 126.86	$ -	$ 7.53	$ -	$ -
TN	321	1	14	$ 39.07	$ 2.92	$ 2.61	$ -	$ -
TN	331	45	753,952	$ 464,859.32	$ 17,750.64	$ 27,265.21	$ -	$ -
TN	341	2	31,629	$ 17,322.12	$ 1,080.20	$ 1,097.64	$ -	$ -
TN	342		22,507	$ 26,563.21				
TN	352	437	1,364,451	$ 1,154,664.07	$ 50,997.39	$ 67,009.00	$ -	$ -
TN	365	21	244,665	$ 109,716.89	$ 530.28	$ -	$ -	$ -
TN	371	82	2,094,065	$ 383,912.73	$ -	$ 24,613.31	$ -	$ -
TN	372	51	7,836,286	$ 404,379.51	$ -	$ 26,237.02	$ -	$ -
TN	373	1	649,205	$ 26,722.18	$ -	$ -	$ -	$ -
TN	381	2	19,870	$ 12,033.38	$ -	$ -	$ -	$ -
TN Total		**171,599**	**25,360,173**	**$ 15,291,355.61**	**$ 295,745.82**	**$ 800,598.15**	**$ -**	**$ -**

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December 2013 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		40		$ 1,173.59	$ -	$ -	$ -	$ -
TN	301	156,070	18,531,355	$ 16,180,392.57	$ 45.20	$ 786,937.16	$ -	$ -
TN	302	16,727	7,554,845	$ 6,537,552.26	$ 385,107.98	$ 375,130.07	$ -	$ -
TN	311	4	441	$ 334.25	$ -	$ 20.32	$ -	$ -
TN	313	4	261	$ 223.83	$ -	$ 14.01	$ -	$ -
TN	321	1	96	$ 94.77	$ 7.08	$ 6.34	$ -	$ -
TN	331	47	947,931	$ 560,802.11	$ 22,164.40	$ 32,582.70	$ -	$ -
TN	341	2	41,106	$ 22,011.23	$ 1,335.94	$ 1,384.25	$ -	$ -
TN	342	1	1,013	$ 729.06	$ 54.45	$ 48.77	$ -	$ -
TN	342		28,359	$ 33,469.86				
TN	352	434	2,472,921	$ 1,998,516.40	$ 86,675.44	$ 115,165.00	$ -	$ -
TN	360	1	1,585,260	$ 633,984.87	$ -	$ -	$ -	$ -
TN	365	21	291,930	$ 149,960.67	$ 155.29	$ 538.60	$ -	$ -
TN	371	82	2,410,865	$ 408,847.82	$ -	$ 26,216.80	$ -	$ -
TN	372	51	8,755,201	$ 438,250.87	$ -	$ 28,385.28	$ -	$ -
TN	373	1	764,491	$ 30,757.19	$ -	$ -	$ -	$ -
TN	381	2	27,630	$ 15,857.43	$ -	$ -	$ -	$ -
TN TOTAL		**173,488**	**43,413,705**	**$ 27,012,958.78**	**$ 495,545.78**	**$ 1,366,429.30**	**$ -**	**$ -**

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January 2014 301-C Adjusted Including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		61		$ 1,518.77	$ -	$ -	$ -	$ -
TN	301	156,942	27,986,950	$ 25,517,818.66	$ 71.16	$ 1,235,195.79	$ -	$ -
TN	302	16,931	11,810,070	$ 10,577,578.98	$ 618,815.01	$ 606,494.82	$ -	$ -
TN	311	10	(620)	$ (529.79)	$ -	$ (31.82)	$ -	$ -
TN	313	15	(259)	$ (269.52)	$ -	$ (15.24)	$ -	$ -
TN	321	2	(110)	$ (133.84)	$ (10.00)	$ (8.95)	$ -	$ -
TN	328	2	15,113	$ 7,236.10	$ -	$ -	$ -	$ -
TN	331	45	1,284,198	$ 760,378.14	$ 30,511.73	$ 43,718.03	$ -	$ -
TN	341	2	38,796	$ 21,073.60	$ 1,526.70	$ 1,396.30	$ -	$ -
TN	342	1		$ 40.00	$ 2.99	$ 2.68	$ -	$ -
TN	342		33,224	$ 39,211.63	$ -	$ -	$ -	$ -
TN	352	423	3,603,556	$ 3,084,697.74	$ 133,395.07	$ 177,956.98	$ -	$ -
TN	361	41	458,036	$ 606,849.46	$ 8,551.21	$ 39,247.72	$ -	$ -
TN	365	22	135,739	$ 87,990.39	$ 262.68	$ -	$ -	$ -
TN	371	88	2,952,561	$ 529,073.85	$ -	$ 33,891.42	$ -	$ -
TN	372	50	8,718,650	$ 491,458.93	$ -	$ 31,356.06	$ -	$ -
TN	373	1	830,826	$ 33,078.91	$ -	$ -	$ -	$ -
TN	381	2	43,638	$ 24,934.27	$ -	$ -	$ -	$ -
TN TOTAL		**174,638**	**57,910,368**	**$ 41,782,006.28**	**$ 793,126.55**	**$ 2,169,203.79**	**$ -**	**$ -**

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February 2014 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		42		$ 988.37	$ -	$ -	$ -	$ -
TN	301	156996	31,323,345	$ 27,497,577.89	$ 80.99	$ 1,296,577.70	$ -	$ -
TN	302	17011	12,487,904	$ 10,972,790.53	$ 634,288.24	$ 617,226.90	$ -	$ -
TN	328	3	24,800	$ 11,874.24	$ 730.44	$ 1,278.49	$ -	$ -
TN	331	45	1,003,822	$ 615,610.07	$ 25,076.85	$ 35,496.91	$ -	$ -
TN	341	2	31,609	$ 17,486.35	$ 1,258.79	$ 1,156.32	$ -	$ -
TN	342	1	24,968	$ 17,023.74	$ 1,271.38	$ 1,138.89	$ -	$ -
TN	342		13,745	$ 16,222.12				
TN	352	427	3,637,196	$ 3,080,229.76	$ 131,150.08	$ 178,742.71	$ -	$ -
TN	360	1	801,000	$ 459,155.00	$ -	$ -	$ -	$ -
TN	365	23	111,942	$ 90,298.60	$ 94.88	$ -	$ -	$ -
TN	371	96	2,477,223	$ 480,066.04	$ -	$ 30,773.41	$ -	$ -
TN	372	50	8,370,700	$ 477,480.20	$ -	$ 30,660.70	$ -	$ -
TN	373	1	756,011	$ 30,460.39	$ -	$ -	$ -	$ -
TN	381	2	29,798	$ 17,737.20	$ -	$ -	$ -	$ -
TN TOTALS		**174,700**	**61,094,063**	**$ 43,785,000.50**	**$ 793,951.65**	**$ 2,193,052.03**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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March 2014 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		32		$ 684.35	$ -	$ -	$ -	$ -
TN	301	157866	20,066,834	$ 18,770,701.25	$ 59.69	$ 896,372.08	$ -	$ -
TN	302	17121	8,303,869	$ 7,573,427.66	$ 441,287.90	$ 428,642.08	$ -	$ -
TN	313	10	-335	$ (376.56)	$ -	$ (26.19)	$ -	$ -
TN	331	45	844,293	$ 532,233.91	$ 21,082.10	$ 31,535.98	$ -	$ -
TN	341	2	33,413	$ 18,454.80	$ 1,052.67	$ 1,141.26	$ -	$ -
TN	342	1	35,347	$ 24,083.74	$ 1,798.65	$ 1,611.20	$ -	$ -
TN	342		18,592	$ 21,942.65				
TN	352	439	2,543,767	$ 2,187,514.80	$ 94,206.23	$ 127,818.79	$ -	$ -
TN	365	21	9,336	$ 6,614.47	$ 335.48	$ -	$ -	$ -
TN	371	83	2,201,958	$ 450,194.11	$ -	$ 28,233.43	$ -	$ -
TN	372	52	8,454,557	$ 484,761.32	$ -	$ 29,744.88	$ -	$ -
TN	373	1	736,003	$ 29,760.11	$ -	$ -	$ -	$ -
TN	381	2	22,487	$ 13,935.33	$ -	$ -	$ -	$ -
TN TOTAL		**175,675**	**43,270,121**	**$ 30,113,931.94**	**$ 559,822.72**	**$ 1,545,073.51**	**$ -**	**$ -**

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April 2014 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		46		$ (827.96)	$ -	$ -	$ -	$ -
TN	301	157,317	11,440,614	$ 12,740,731.32	$ 48.38	$ 595,052.96	$ -	$ -
TN	302	17,099	4,898,764	$ 5,432,450.27	$ 319,035.26	$ 305,776.31	$ -	$ -
TN	331	45	429,491	$ 384,191.78	$ 14,028.22	$ 23,772.59	$ -	$ -
TN	341	2	21,568	$ 15,825.82	$ 702.99	$ 921.41	$ -	$ -
TN	342	1	41,367	$ 34,751.46	$ 2,595.34	$ 2,324.87	$ -	$ -
TN	342		21,938	$ 29,377.40				
TN	352	446	1,571,835	$ 1,606,070.33	$ 66,495.65	$ 95,558.02	$ -	$ -
TN	360	1	1,600,000	$ 732,755.00	$ -	$ -	$ -	$ -
TN	365	22	3,953	$ (542.99)	$ 426.02	$ 578.29	$ -	$ -
TN	371	83	1,461,059	$ 375,974.13	$ -	$ 24,716.37	$ -	$ -
TN	372	52	6,133,761	$ 386,035.33	$ -	$ 26,856.02	$ -	$ -
TN	373	1	476,306	$ 20,670.71	$ -	$ -	$ -	$ -
TN	381	2	7,462	$ 7,396.18	$ -	$ -	$ -	$ -
TN TOTAL		**175,117**	**28,108,118**	**$ 21,764,858.78**	**$ 403,331.86**	**$ 1,075,556.84**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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May 2014 301-C Adjusted including CNG

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		41		$ 883.58	$ -	$ -	$ -	$ -
TN	301	156,668	4,189,393	$ 6,074,377.53	$ 25.12	$ 276,804.00	$ -	$ -
TN	302	16,759	2,573,926	$ 3,441,988.44	$ 200,063.79	$ 177,284.90	$ -	$ -
TN	331	49	331,131	$ 317,637.70	$ 11,586.58	$ 18,943.89	$ -	$ -
TN	341	2	5,429	$ 5,180.86	$ 240.91	$ 297.02	$ -	$ -
TN	342	1	44,184	$ 37,115.24	$ 2,764.34	$ 2,375.38	$ -	$ -
TN	342		15,215	$ 20,374.56				
TN	352	430	843,170	$ 916,339.68	$ 37,054.61	$ 52,831.16	$ -	$ -
TN	365	21	116,709	$ 63,741.44	$ 30.90	$ 123.89	$ -	$ -
TN	371	82	1,272,261	$ 352,193.70	$ -	$ 21,638.47	$ -	$ -
TN	372	51	5,637,203	$ 366,046.76	$ -	$ 22,931.30	$ -	$ -
TN	373	1	433,170	$ 19,160.95	$ -	$ -	$ -	$ -
TN	381	2	4,109	$ 5,139.01	$ -	$ -	$ -	$ -
TN TOTAL		**174,107**	**15,465,900**	**$ 11,620,179.45**	**$ 251,766.25**	**$ 573,230.01**	**$ -**	**$ -**

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Piedmont Natural Gas
June 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		33		$ (170.97)	$ -	$ -	$ -	$ -
TN	301	155,836	2,430,711	$ 4,394,853.96	$ 8.62	$ 201,015.34	$ -	$ -
TN	302	16,715	1,956,588	$ 2,619,807.57	$ 168,085.49	$ 142,709.17	$ -	$ -
TN	331	41	273,807	$ 291,628.17	$ 11,459.56	$ 17,655.04	$ -	$ -
TN	341	2	22,292	$ 16,250.20	$ 302.92	$ 823.71	$ -	$ -
TN	342	2	58,149	$ 48,873.40	$ 3,640.09	$ 3,127.90	$ -	$ -
TN	342		19,027	$ 25,479.25				
TN	352	359	591,242	$ 652,885.21	$ 27,949.59	$ 38,266.72	$ -	$ -
TN	365	22	116,267	$ 61,620.62	$ 88.66	$ -	$ -	$ -
TN	371	77	1,096,348	$ 358,747.97	$ -	$ 22,174.73	$ -	$ -
TN	372	51	5,354,303	$ 351,118.24	$ -	$ 22,030.84	$ -	$ -
TN	373	1	414,992	$ 18,524.72	$ -	$ -	$ -	$ -
TN	381	2	2,825	$ 4,274.64	$ -	$ -	$ -	$ -
TN TOTAL		**173,141**	**12,336,551**	**$ 8,843,892.98**	**$ 211,534.93**	**$ 447,803.45**	**$ -**	**$ -**

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Piedmont Natural Gas
July 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		44		$ 500.45	$ -	$ -	$ -	$ -
TN	301	155,722	1,868,619	$ 3,858,608.40	$ 7.80	$ 177,287.70	$ -	$ -
TN	302	16,437	1,858,978	$ 2,515,204.94	$ 162,663.31	$ 137,368.01	$ -	$ -
TN	311	1	-172	$ (172.87)	$ -	$ -	$ -	$ -
TN	331	43	288,118	$ 301,320.25	$ 11,775.15	$ 18,302.18	$ -	$ -
TN	341	2	20,696	$ 15,209.14	$ 286.52	$ 771.66	$ -	$ -
TN	342	3	83,885	$ 70,508.74	$ 5,251.31	$ 4,510.00	$ -	$ -
TN	342		14,364	$ 19,234.98				
TN	352	356	520,714	$ 584,388.56	$ 25,298.47	$ 34,398.38	$ -	$ -
TN	365	28	40,719	$ 24,124.95	$ (87.88)	$ 3.12	$ -	$ -
TN	371	76	1,117,265	$ 358,787.10	$ -	$ 22,170.39	$ -	$ -
TN	372	51	5,854,986	$ 370,945.02	$ -	$ 23,291.30	$ -	$ -
TN	373	1	357,352	$ 16,507.32	$ -	$ -	$ -	$ -
TN	381	3	1,302	$ 3,249.39	$ -	$ -	$ -	$ -
TN TOTAL		**172,767**	**12,026,826**	**$ 8,138,416.37**	**$ 205,194.68**	**$ 418,102.74**	**$ -**	**$ -**

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Piedmont Natural Gas
August 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		42		$ 694.47	$ -	$ -	$ -	$ -
TN	301	154,998	1,797,861	$ 3,783,961.73	$ 87.49	$ 175,242.00	$ -	$ -
TN	302	16,239	1,731,995	$ 2,386,037.94	$ 154,137.04	$ 130,237.76	$ -	$ -
TN	331	43	280,443	$ 296,092.25	$ 11,595.85	$ 17,980.09	$ -	$ -
TN	341	2	18,476	$ 13,761.06	$ 263.72	$ 699.25	$ -	$ -
TN	342	5	98,021	$ 82,370.39	$ 329.03	$ 4,970.88	$ -	$ -
TN	342		16,048	$ 21,490.04				
TN	352	358	500,245	$ 564,547.53	$ 24,154.45	$ 33,433.88	$ -	$ -
TN	365	22	15,539	$ 7,795.33	$ -	$ -	$ -	$ -
TN	371	80	1,105,289	$ 357,008.26	$ -	$ 22,083.25	$ -	$ -
TN	372	53	5,974,280	$ 374,550.67	$ -	$ 23,545.18	$ -	$ -
TN	373	1	418,445	$ 18,645.58	$ -	$ -	$ -	$ -
TN	381	2		$ 2,372.91	$ -	$ -	$ -	$ -
TN TOTAL		**171,845**	**11,956,642**	**$ 7,909,328.16**	**$ 190,567.58**	**$ 408,192.29**	**$ -**	**$ -**

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Piedmont Natural Gas
September 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		56		$ 951.40	$ -	$ -	$ -	$ -
TN	301	154,885	1,796,926	$ 3,779,881.78	$ 7.46	$ 175,607.94	$ -	$ -
TN	302	19,474	1,756,489	$ 2,411,292.92	$ 154,529.60	$ 133,776.21	$ -	$ -
TN	331	41	293,458	$ 304,948.24	$ 12,042.22	$ 16,691.74	$ -	$ -
TN	341	2	10,204	$ 8,330.36	$ 235.71	$ 441.43	$ -	$ -
TN	342	7	90,606	$ 76,148.40	$ 4,191.55	$ 4,716.16	$ -	$ -
TN	342		16,412	$ 21,977.47	$ -	$ -	$ -	$ -
TN	352	370	523,060	$ 587,508.64	$ 24,966.56	$ 34,741.57	$ -	$ -
TN	365	19	62,260	$ 27,761.72	$ -	$ 1,267.58	$ -	$ -
TN	371	76	1,165,486	$ 363,817.36	$ -	$ 20,723.07	$ -	$ -
TN	372	56	6,138,654	$ 384,189.78	$ (4,331.43)	$ 18,413.13	$ -	$ -
TN	373	1	395,815	$ 17,853.53	$ -	$ -	$ -	$ -
TN	381	2		$ 2,372.91	$ -	$ -	$ -	$ -
TN TOTALS		**174,989**	**12,249,370**	**$ 7,987,034.51**	**$ 191,641.67**	**$ 406,378.83**	**$ -**	**$ -**

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Piedmont Natural Gas
October 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		67		$ 1,026.86	$ -	$ -	$ -	$ -
TN	301	155,109	2407152	$ 4,554,812.98	$ 10.99	$ 212,743.81	$ -	$ -
TN	302	16,263	2116972	$ 2,856,044.88	$ 179,628.02	$ 159,590.57	$ -	$ -
TN	331	45	349673	$ 343,004.99	$ 14,294.88	$ 21,733.58	$ -	$ -
TN	341	2	20723	$ 15,268.48	$ 615.33	$ 852.78	$ -	$ -
	342	3	20060	$ 26,862.55				
TN	342	3	86910	$ 73,047.06	$ 3,816.73	$ 4,662.84	$ -	$ -
TN	352	363	669128	$ 756,187.74	$ 32,957.08	$ 43,867.58	$ -	$ -
TN	360	1	50000	$ 19,850.00	$ -	$ -	$ -	$ -
TN	365	21	84261	$ 39,312.34	$ -	$ (1,267.58)	$ -	$ -
TN	371	94	1435407	$ 394,986.73	$ -	$ 26,555.90	$ -	$ -
TN	372	72	6615173	$ 413,044.72	$ -	$ 31,579.11	$ -	$ -
TN	373	1	529698	$ 22,539.43	$ -	$ -	$ -	$ -
TN	381	2		$ 2,372.91	$ -	$ -	$ -	$ -
TN TOTAL		**172,046**	**14,385,157**	**$ 9,518,361.67**	**$ 231,323.03**	**$ 500,318.59**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
November 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		67		$ 1,230.63	$ -	$ -	$ -	$ -
TN	301	156032	9,078,222	$ 11,366,220.37	$ 32.36	$ 544,974.78	$ -	$ -
TN	302	16967	4,385,534	$ 5,010,359.79	$ 299,291.95	$ 282,984.20	$ -	$ -
TN	331	41	703,976	$ 584,800.77	$ 27,025.83	$ 31,443.90	$ -	$ -
TN	341	6	31,687	$ 22,486.27	$ 1,470.24	$ 1,390.36	$ -	$ -
TN	342	3	96,505	$ 81,336.68	$ 4,265.05	$ 5,103.29	$ -	$ -
TN	342		12,916	$ 17,327.84				
TN	352	368	1,472,839	$ 1,519,693.98	$ 69,461.57	$ 86,120.30	$ -	$ -
TN	365	19	384,068	$ 185,915.67	$ 36.09	$ 144.72	$ -	$ -
TN	371	228	2,071,123	$ 467,115.28	$ -	$ 29,116.98	$ -	$ -
TN	372	152	8,620,108	$ 491,653.90	$ -	$ 30,448.45	$ -	$ -
TN	373	3	673,414	$ 27,569.49	$ -	$ -	$ -	$ -
TN	381	1		$ 593.23	$ -	$ -	$ -	$ -
TN Total		**173,887**	**27,530,392**	**$ 19,776,303.90**	**$ 401,583.09**	**$ 1,011,726.98**	**$ -**	**$ -**

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Piedmont Natural Gas
December 2014 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		82		$ 1,079.26	$ -	$ -	$ -	$ -
TN	301	158135	17,949,027	$ 19,971,581.51	$ (22.30)	$ 920,161.82	$ -	$ -
TN	302	17197	7,921,400	$ 8,660,583.20	$ 486,640.91	$ 486,319.81	$ -	$ -
TN	313	4		$ (52.00)	$ -	$ -	$ -	$ -
TN	331	41	831,622	$ 671,352.62	$ 30,963.36	$ 35,814.06	$ -	$ -
TN	341	2	34,323	$ 24,221.79	$ 1,548.45	$ 1,489.27	$ -	$ -
TN	342	3	89,252	$ 75,232.69	$ 3,897.56	$ 4,682.26	$ -	$ -
TN	342		13,714	$ 18,398.43				
TN	352	399	2,278,822	$ 2,356,886.93	$ 103,646.97	$ 133,282.56	$ -	$ -
TN	360	1	3,139,990	$ 1,325,075.78	$ -	$ -	$ -	$ -
TN	365	24	310,118	$ 150,893.53	$ -	$ -	$ -	$ -
TN	371	78	2,233,427	$ 482,727.12	$ -	$ 30,119.14	$ -	$ -
TN	372	54	9,320,663	$ 514,734.27	$ -	$ 32,289.29	$ -	$ -
TN	373	1	687,251	$ 28,053.79	$ -	$ -	$ -	$ -
TN	381	1		$ 593.23	$ -	$ -	$ -	$ -
TN TOTALS		**176,022**	**44,809,609**	**$ 34,281,362.15**	**$ 626,674.95**	**$ 1,644,158.21**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
January 2015 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		66		$ 917.84	$ -	$ -	$ -	$ -
TN	301	158805	25,622,995	$ 28,443,022.74	$ 69.06	$ 1,314,905.51	$ -	$ -
TN	302	17313	10,801,835	$ 11,832,348.20	$ 694,977.87	$ 658,102.93	$ -	$ -
TN	331	49	1,102,811	$ 854,414.45	$ 39,252.89	$ 45,114.72	$ -	$ -
TN	341	2	31,615	$ 22,409.59	$ 1,622.08	$ 1,423.01	$ -	$ -
TN	342	3	104,991	$ 88,478.32	$ 4,377.90	$ 5,564.34	$ -	$ -
TN	342		25,908	$ 34,757.65				
TN	352	358	2,992,015	$ 3,140,696.70	$ 139,963.79	$ 177,271.04	$ -	$ -
TN	361	40	0	$ 475,397.84	$ 10,728.15	$ 22,506.24	$ -	$ -
TN	365	22	0	$ -	$ -	$ -	$ -	$ -
TN	371	81	2,516,617	$ 511,399.01	$ -	$ 31,898.63	$ -	$ -
TN	372	51	9,626,687	$ 521,731.67	$ -	$ 32,521.62	$ -	$ -
TN	373	3	756,802	$ 30,488.07	$ -	$ -	$ -	$ -
TN	381	1		$ 593.23	$ -	$ -	$ -	$ -
TN Totals		**176,794**	**53,582,276**	**$ 45,956,655.31**	**$ 890,991.74**	**$ 2,289,308.04**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
February 2015 - 301C
TN Revised for Actual

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		81		$ 1,513.90	$ -	$ -	$ -	$ -
TN	301	159,052	25,707,206	$ 28,716,227.35	$ 75.48	$ 1,314,800.25	$ -	$ -
TN	302	17,355	11,245,581	$ 12,230,214.90	$ 695,716.97	$ 677,517.56	$ -	$ -
TN	328	1	17,536	$ 6,635.62	$ 494.22	$ 424.68	$ -	$ -
TN	331	41	1,105,499	$ 866,057.74	$ 41,264.14	$ 44,969.51	$ -	$ -
TN	341	2	37,863	$ 26,583.83	$ 1,932.98	$ 1,690.17	$ -	$ -
TN	342	3	99,038	$ 83,468.41	$ 3,981.72	$ 5,286.20	$ -	$ -
TN	342		7,837	$ 10,513.96				
TN	352	361	2,941,984	$ 3,078,750.03	$ 139,088.37	$ 174,132.09	$ -	$ -
TN	361	43	-	$ 411,808.79	$ 7,514.45	$ 24,335.32	$ -	$ -
TN	365	14	102,865	$ 36,858.38	$ 18.35	$ 73.60	$ -	$ -
TN	371	78	2,527,713	$ 536,174.05	$ -	$ 33,468.19	$ -	$ -
TN	372	53	9,089,166	$ 519,461.08	$ 349.44	$ 32,198.18	$ -	$ -
TN	373	5	614,930	$ 25,522.55	$ 3.12	$ -	$ -	$ -
TN	381	1		$ 593.23	$ -	$ -	$ -	$ -
TN TOTAL		**177,090**	**53,497,218**	**$ 46,550,383.82**	**$ 890,439.24**	**$ 2,308,895.75**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
March 2015 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		85		$ 1,553.63	$ -	$ -	$ -	$ -
TN	301	160039	26,057,214	$ 21,234,168.15	$ 47.65	$ 951,699.86	$ -	$ -
TN	302	17379	10,651,066	$ 8,614,661.79	$ 488,706.66	$ 471,172.88	$ -	$ -
TN	328	1	21,392	$ 6,584.46	$ 490.41	$ 421.41	$ -	$ -
TN	331	43	802,557	$ 480,028.65	$ 22,340.76	$ 26,539.92	$ -	$ -
TN	341	2	25,289	$ 12,212.28	$ 706.89	$ 733.27	$ -	$ -
TN	352	369	2,717,177	$ 2,098,236.13	$ 91,471.43	$ 120,075.09	$ -	$ -
TN	361	4		$ -	$ -	$ -	$ -	$ -
TN	365	21	21,192	$ 6,660.65	$ 62.19	$ 249.37	$ -	$ -
TN	371	79	2,008,072	$ 513,385.88	$ -	$ 32,026.92	$ -	$ -
TN	372	51	8,811,328	$ 512,245.56	$ -	$ 32,048.91	$ -	$ -
TN	373	5	634,717	$ 26,215.10	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTAL		**178,079**	**51,750,004**	**$ 33,506,667.53**	**$ 603,825.99**	**$ 1,634,967.63**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
April 2015 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		81		$ 1,785.32	$ -	$ -	$ -	$ -
TN	301	160,287	9,158,282	$ 9,499,897.43	$ 32.67	$ 432,057.12	$ -	$ -
TN	302	17,311	4,462,471	$ 4,401,340.71	$ 260,026.07	$ 243,471.27	$ -	$ -
TN	331	50	523,627	$ 373,027.72	$ 16,905.96	$ 22,023.59	$ -	$ -
TN	341	2	13,637	$ 7,338.32	$ 339.85	$ 420.38	$ -	$ -
TN	342	13	(32,990)	$ (27,803.74)	$ (2,135.75)	$ (1,748.95)	$ -	$ -
TN	352	357	1,320,938	$ 1,167,561.28	$ 47,589.04	$ 68,098.90	$ -	$ -
TN	360	1	992,000	$ 246,208.00	$ -	$ -	$ -	$ -
TN	365	17	130,408	$ 39,488.32	$ 20.66	$ 82.85	$ -	$ -
TN	371	80	1,376,005	$ 435,809.63	$ -	$ 27,155.97	$ -	$ -
TN	372	51	7,249,320	$ 445,490.14	$ -	$ 27,988.30	$ -	$ -
TN	373	3	480,118	$ 20,804.13	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTALS		**178,254**	**25,673,816**	**$ 16,611,662.51**	**$ 322,778.50**	**$ 819,549.43**	**$ -**	**$ -**

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Piedmont Natural Gas
May 2015 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		101		$ 1,562.53	$ -	$ -	$ -	$ -
TN	301	158,921	3,598,743	$ 4,802,728.95	$ 18.44	$ 223,552.68	$ -	$ -
TN	302	16,971	2,461,193	$ 2,991,278.64	$ 163,888.34	$ 146,758.25	$ -	$ -
TN	331	44	401,669	$ 300,361.23	$ 13,445.42	$ 17,956.44	$ -	$ -
TN	341	2	3,534	$ 3,087.08	$ 151.24	$ 180.36	$ -	$ -
TN	352	355	655,376	$ 572,818.51	$ 25,906.56	$ 32,971.80	$ -	$ -
TN	360	1	-	$ -	$ -	$ -	$ -	$ -
TN	365	19	61,481	$ 19,237.40	$ -	$ -	$ -	$ -
TN	371	81	1,182,880	$ 413,325.85	$ -	$ 26,132.60	$ -	$ -
TN	372	51	6,533,624	$ 414,778.24	$ -	$ 26,397.34	$ -	$ -
TN	373	1	425,357	$ 18,887.50	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTALS		**176,548**	**15,323,857**	**$ 9,538,781.18**	**$ 203,410.00**	**$ 473,949.47**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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Piedmont Natural Gas
June 2015 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		101		$ 1,352.26	$ -	$ -	$ -	$ -
TN	301	158536	2,340,039	$ 3,862,168.76	$ 18.12	$ 178,914.33	$ -	$ -
TN	302	16777	1,953,938	$ 2,214,412.19	$ 143,532.69	$ 123,578.96	$ -	$ -
TN	331	43	385,446	$ 296,481.78	$ 13,501.32	$ 17,839.09	$ -	$ -
TN	341	2	5,132	$ 3,759.49	$ 106.24	$ 199.89	$ -	$ -
TN	352	361	564,364	$ 508,335.57	$ 22,213.44	$ 29,556.85	$ -	$ -
TN	365	15	53,431	$ 20,686.76	$ -	$ -	$ -	$ -
TN	371	78	1,115,487	$ 401,565.36	$ -	$ 25,398.27	$ -	$ -
TN	372	51	6,468,083	$ 412,923.36	$ -	$ 26,287.05	$ -	$ -
TN	373	1	410,089	$ 18,353.12	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTAL		**175,966**	**13,296,009**	**$ 7,740,753.90**	**$ 179,371.81**	**$ 401,774.44**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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Piedmont Natural Gas
July 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		112		$ (11.47)	$ -	$ -	$ -	$ -
TN	301	158,844	2,004,384	$ 3,611,023.56	$ 14.27	$ 169,729.69	$ -	$ -
TN	302	16,548	1,949,581	$ 2,204,336.13	$ 143,334.42	$ 123,382.94	$ -	$ -
TN	331	47	387,723	$ 296,924.33	$ 13,742.08	$ 17,885.14	$ -	$ -
TN	341	2	641	$ 1,869.73	$ 76.48	$ 105.41	$ -	$ -
TN	352	367	521,087	$ 474,939.71	$ 20,715.46	$ 27,509.03	$ -	$ -
TN	365	18	60,487	$ 19,896.87	$ -	$ -	$ -	$ -
TN	371	80	1,083,744	$ 398,021.53	$ -	$ 25,174.38	$ -	$ -
TN	372	51	6,646,775	$ 419,014.83	$ -	$ 26,686.96	$ -	$ -
TN	373	1	366,139	$ 16,814.87	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTAL		**176,071**	**13,020,561**	**$ 7,443,545.34**	**$ 177,882.71**	**$ 390,473.55**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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Piedmont Natural Gas
August 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		118		$ 2,587.85	$ -	$ -	$ -	$ -
TN	301	157,427	1,732,161	$ 3,397,064.94	$ 15.45	$ 159,265.29	$ -	$ -
TN	302	16,412	1,795,963	$ 2,083,439.49	$ 133,227.36	$ 116,995.16	$ -	$ -
TN	331	43	402,407	$ 302,815.51	$ 13,858.14	$ 18,269.46	$ -	$ -
TN	341	2	17,849	$ 9,089.99	$ 190.47	$ 466.49	$ -	$ -
TN	352	347	460,297	$ 427,668.16	$ 18,424.48	$ 25,067.81	$ -	$ -
TN	365	19	56,450	$ 25,740.83	$ 5.05	$ 20.50	$ -	$ -
TN	371	78	1,137,184	$ 405,035.06	$ -	$ 25,591.52	$ -	$ -
TN	372	51	6,896,731	$ 429,236.46	$ -	$ 27,358.01	$ -	$ -
TN	373	1	436,449	$ 19,275.72	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTAL		**174,499**	**12,935,491**	**$ 7,102,669.26**	**$ 165,720.95**	**$ 373,034.24**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.

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Piedmont Natural Gas
September 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		139		$ 1,622.25	$ -	$ -	$ -	$ -
TN	301	157,480	1,875,800	$ 3,502,507.84	$ 12.90	$ 164,042.11	$ -	$ -
TN	302	16,317	1,785,101	$ 2,073,265.34	$ 135,953.35	$ 115,808.75	$ -	$ -
TN	328	15	92,680	$ 28,887.31	$ -	$ 1,852.74	$ -	$ -
TN	331	44	390,064	$ 302,703.48	$ 14,388.03	$ 18,156.50	$ -	$ -
TN	341	2	16,145	$ 8,393.66	$ 226.11	$ 443.48	$ -	$ -
TN	352	345	513,008	$ 466,904.95	$ 19,581.78	$ 27,181.68	$ -	$ -
TN	365	17	59,801	$ 20,841.76	$ 11.25	$ 45.73	$ -	$ -
TN	371	106	1,247,698	$ 418,000.73	$ -	$ 26,483.34	$ -	$ -
TN	372	51	6,754,020	$ 422,780.11	$ -	$ 26,962.82	$ -	$ -
TN	373	1	416,449	$ 18,575.72	$ -	$ -	$ -	$ -
TN	381	1		$ 715.25	$ -	$ -	$ -	$ -
TN TOTALS		**174,518**	**13,150,766**	**$ 7,265,198.40**	**$ 170,173.42**	**$ 380,977.15**	**$ -**	**$ -**

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Piedmont Natural Gas
October 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		62		$ 891.02	$ -	$ -	$ -	$ -
TN	301	157651	2,637,027	$ 4,198,069.78	$ 17.49	$ 198,913.68	$ -	$ -
TN	302	16484	2,218,312	$ 2,467,267.68	$ 156,962.71	$ 139,068.52	$ -	$ -
TN	331	44	478,887	$ 342,073.89	$ 16,398.52	$ 20,407.68	$ -	$ -
TN	341	2	22,371	$ 11,013.50	$ 437.68	$ 617.64	$ -	$ -
TN	352	341	651,665	$ 592,401.02	$ 25,559.41	$ 34,475.57	$ -	$ -
TN	365	19	47,428	$ 12,940.95	$ 1.41	$ 5.73	$ -	$ -
TN	371	82	1,411,808	$ 439,658.77	$ -	$ 27,909.31	$ -	$ -
TN	372	51	7,187,351	$ 447,717.82	$ -	$ 28,512.68	$ -	$ -
TN	373	1	509,073	$ 21,817.56	$ -	$ -	$ -	$ -
TN	381	1	21	$ 724.51	$ -	$ -	$ -	$ -
TN TOTAL		**174,738**	**15,163,943**	**$ 8,534,576.50**	**$ 199,377.22**	**$ 449,910.81**	**$ -**	**$ -**

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Piedmont Natural Gas
November 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		75		$ 741.47	$ -	$ -	$ -	$ -
TN	301	158,856	4,942,044	$ 7,005,458.40	$ 29.59	$ 336,541.06	$ -	$ -
TN	302	16,786	2,906,241	$ 3,232,816.33	$ 200,750.63	$ 182,758.07	$ -	$ -
TN	311	1	35	$ 37.33	$ -	$ -	$ -	$ -
TN	331	50	627,301	$ 398,653.36	$ 18,175.69	$ 23,143.98	$ -	$ -
TN	341	2	14,471	$ 7,430.52	$ 500.62	$ 468.74	$ -	$ -
TN	352	342	906,525	$ 859,635.78	$ 38,172.45	$ 49,701.37	$ -	$ -
TN	360	1	460,000	$ 93,350.00	$ -	$ -	$ -	$ -
TN	365	18	1,733	$ 467.81	$ -	$ -	$ -	$ -
TN	371	79	1,687,136	$ 476,741.27	$ -	$ 30,156.14	$ -	$ -
TN	372	53	7,724,143	$ 468,173.45	$ -	$ 29,774.06	$ -	$ -
TN	373	1	623,774	$ 25,832.09	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTAL		**176,265**	**19,893,403**	**$ 12,570,053.72**	**$ 257,628.98**	**$ 652,543.42**	**$ -**	**$ -**

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Piedmont Natural Gas
December 2015 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		79		$ 1,566.00	$ -	$ -	$ -	$ -
TN	301	160526	11,165,821	$ 13,061,398.76	$ 59.26	$ 610,470.35	$ -	$ -
TN	302	17215	5,026,025	$ 5,527,517.47	$ 330,035.89	$ 312,994.96	$ -	$ -
TN	311	1	98	$ 90.51	$ -	$ -	$ -	$ -
TN	331	48	741,539	$ 446,342.40	$ 21,101.58	$ 25,232.33	$ -	$ -
TN	341	2	19,722	$ 9,543.11	$ 562.48	$ 581.62	$ -	$ -
TN	352	347	1,468,378	$ 1,467,697.95	$ 65,578.86	$ 84,876.81	$ -	$ -
TN	360	3	720,000	$ 160,760.00	$ -	$ -	$ -	$ -
TN	365	15	240,720	$ 72,629.91	$ 12.89	$ 52.36	$ -	$ -
TN	371	79	1,830,518	$ 496,406.20	$ -	$ 31,376.21	$ -	$ -
TN	372	55	8,713,752	$ 504,090.96	$ -	$ 32,078.50	$ -	$ -
TN	373	1	718,481	$ 29,146.84	$ -	$ -	$ -	$ -
		1		$ 715.91	$ -	$ -	$ -	$ -
		178,372	**30,645,054**	**$ 21,777,906.02**	**$ 417,350.96**	**$ 1,097,663.14**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
January 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		88		$ 2,916.36	$ -	$ -	$ -	$ -
TN	301	161003	18,493,458	$ 17,948,032.33	$ 65.95	$ 849,388.99	$ -	$ -
TN	302	17363	8,645,897	$ 7,805,159.32	$ 459,570.14	$ 442,785.16	$ -	$ -
TN	311	1	144	$ 134.81	$ -	$ -	$ -	$ -
TN	331	44	1,161,701	$ 541,270.73	$ 26,770.71	$ 29,336.40	$ -	$ -
TN	341	2	28,388	$ 11,031.40	$ 775.28	$ 704.02	$ -	$ -
TN	352	358	2,294,273	$ 1,935,298.73	$ 87,183.08	$ 111,309.85	$ -	$ -
TN	365	22	19,127	$ 5,727.01	$ -	$ -	$ -	$ -
TN	371	80	2,683,287	$ 577,745.61	$ -	$ 36,408.10	$ -	$ -
TN	372	50	10,737,494	$ 564,193.38	$ -	$ 35,685.09	$ -	$ -
TN	373	1	884,705	$ 34,964.68	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
		179,013	**44,948,474**	**$ 29,427,190.27**	**$ 574,365.16**	**$ 1,505,617.61**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
February 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		118		$ 71.09	$ -	$ -	$ -	$ -
TN	301	161924	23,221,552	$ 18,865,809.65	$ 61.48	$ 869,070.09	$ -	$ -
TN	302	17608	10,080,158	$ 8,022,276.68	$ 464,492.82	$ 448,167.81	$ -	$ -
TN	311	1	184	$ 139.98	$ -	$ -	$ -	$ -
TN	331	46	970,540	$ 473,895.54	$ 22,945.41	$ 26,412.49	$ -	$ -
TN	341	2	19,386	$ 8,075.32	$ 554.92	$ 512.17	$ -	$ -
TN	352	358	2,452,795	$ 1,852,282.99	$ 84,511.05	$ 106,766.58	$ -	$ -
TN	360	1	100,000	$ 22,000.00	$ -	$ -	$ -	$ -
TN	362	1	24,872	$ 5,519.10	$ 411.41	$ 358.19	$ -	$ -
TN	365	15	134,483	$ 36,479.86	$ -	$ -	$ -	$ -
TN	371	84	2,253,958	$ 532,626.22	$ -	$ 33,540.36	$ -	$ -
TN	372	49	9,419,749	$ 512,556.78	$ -	$ 32,584.43	$ -	$ -
TN	373	1	785,354	$ 31,487.39	$ -	$ -	$ -	$ -
TN	381	2		$ 715.91	$ -	$ -	$ -	$ -
		180,210	**49,463,031**	**$ 30,363,936.51**	**$ 572,977.09**	**$ 1,517,412.12**	**$ -**	**$ -**

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Piedmont Natural Gas
March 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		107		$ 3,286.64	$ -	$ -	$ -	$ -
TN	301	162,807	16,284,783	$ 15,159,031.73	$ 52.66	$ 699,127.49	$ -	$ -
TN	302	17,539	7,449,190	$ 6,581,698.27	$ 386,016.75	$ 368,172.10	$ -	$ -
TN	311	1	159	$ 119.80	$ -	$ -	$ -	$ -
TN	331	46	647,513	$ 358,588.60	$ 17,166.96	$ 20,984.79	$ -	$ -
TN	341	2	12,064	$ 5,649.52	$ 372.38	$ 354.30	$ -	$ -
TN	352	383	1,861,459	$ 1,545,176.05	$ 66,500.95	$ 88,865.21	$ -	$ -
TN	360	1	202,200	$ 34,475.10	$ -	$ -	$ -	$ -
TN	365	13	194,406	$ 43,355.47	$ 26.69	$ 108.43	$ -	$ -
TN	371	80	1,767,021	$ 478,156.09	$ -	$ 30,187.28	$ -	$ -
TN	372	49	8,505,392	$ 480,255.78	$ -	$ 30,529.65	$ -	$ -
TN	373	1	630,634	$ 26,072.19	$ -	$ -	$ -	$ -
TN	381	4		$ 715.91	$ -	$ -	$ -	$ -
TN TOTALS		**181,033**	**37,554,821**	**$ 24,716,581.15**	**$ 470,136.39**	**$ 1,238,329.25**	**$ -**	**$ -**

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Piedmont Natural Gas
April 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		83		$ 864.08	$ -	$ -	$ -	$ -
TN	301	162382	7,981,386	$ 7,989,402.57	$ 30.00	$ 365,847.66	$ -	$ -
TN	302	17459	3,905,905	$ 3,640,274.23	$ 221,297.10	$ 202,146.83	$ -	$ -
TN	311	2	86	$ 92.12	$ -	$ 0.84	$ -	$ -
TN	331	44	492,127	$ 303,975.66	$ 14,471.58	$ 17,971.90	$ -	$ -
TN	341	2	7,885	$ 4,246.76	$ 261.63	$ 261.69	$ -	$ -
TN	352	384	1,119,340	$ 897,950.34	$ 38,958.97	$ 52,694.10	$ -	$ -
TN	360	1	540,000	$ 100,822.50	$ -	$ -	$ -	$ -
TN	365	15	65,716	$ 13,997.51	$ 20.04	$ 81.41	$ -	$ -
TN	371	80	1,484,403	$ 443,371.05	$ -	$ 28,078.37	$ -	$ -
TN	372	49	7,590,973	$ 444,737.78	$ -	$ 28,310.38	$ -	$ -
TN	373	1	485,081	$ 20,977.84	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
		180,503	**23,672,902**	**$ 13,861,428.35**	**$ 275,039.32**	**$ 695,393.18**	**$ -**	**$ -**

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Piedmont Natural Gas
May 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		74		$ 2,235.40	$ -	$ -	$ -	$ -
TN	301	162133	3,849,386	$ 4,643,430.35	$ 17.87	$ 206,916.54	$ -	$ -
TN	302	17138	2,620,591	$ 2,487,125.85	$ 156,718.92	$ 133,856.52	$ -	$ -
TN	311	1	54	$ 46.81	$ -	$ -	$ -	$ -
TN	331	46	439,496	$ 281,889.04	$ 13,216.44	$ 16,023.80	$ -	$ -
TN	341	2	35,442	$ 13,391.25	$ 375.02	$ 703.18	$ -	$ -
TN	352	355	721,923	$ 556,016.24	$ 24,408.50	$ 31,417.15	$ -	$ -
TN	365	23	70,668	$ 18,339.97	$ (0.07)	$ (0.27)	$ -	$ -
TN	371	79	1,298,017	$ 419,014.97	$ -	$ 25,386.93	$ -	$ -
TN	372	51	7,409,978	$ 435,620.77	$ -	$ 26,526.73	$ -	$ -
TN	373	1	383,364	$ 17,417.74	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTAL		**179,904**	**16,828,919**	**$ 8,875,244.30**	**$ 194,736.68**	**$ 440,830.58**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
June 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		83		$ (11.05)	$ -	$ -	$ -	$ -
TN	301	163,321	2,713,041	$ 3,910,000.18	$ 12.37	$ 174,733.85	$ -	$ -
TN	302	16,966	2,122,682	$ 2,135,481.65	$ 140,570.91	$ 114,673.21	$ -	$ -
TN	311	7	(760)	$ (648.36)	$ -	$ -	$ -	$ -
TN	331	48	396,253	$ 264,678.93	$ 12,657.82	$ 15,206.42	$ -	$ -
TN	341	2	13,314	$ 6,069.11	$ 142.46	$ 313.06	$ -	$ -
TN	352	556	737,447	$ 610,534.37	$ 27,781.18	$ 34,129.28	$ -	$ -
TN	365	32	88,139	$ 24,286.93	$ 28.93	$ 112.53	$ -	$ -
TN	371	85	1,106,745	$ 390,244.75	$ -	$ 23,563.00	$ -	$ -
TN	372	55	6,706,132	$ 404,849.25	$ -	$ 24,652.81	$ -	$ -
TN	373	3	355,636	$ 16,447.26	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTAL		**181,159**	**14,238,629**	**$ 7,762,648.93**	**$ 181,193.67**	**$ 387,384.16**	**$ -**	**$ -**

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Piedmont Natural Gas
July 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		78		$ (1,290.64)	$ -	$ -	$ -	$ -
TN	301	161,122	1,888,665	$ 3,372,673.28	$ 10.50	$ 152,925.59	$ -	$ -
TN	302	16,437	1,726,429	$ 1,863,240.35	$ 122,875.14	$ 99,785.46	$ -	$ -
TN	331	48	364,574	$ 258,951.86	$ 12,446.44	$ 14,855.03	$ -	$ -
TN	341	2	21	$ 1,607.05	$ 72.18	$ 89.95	$ -	$ -
TN	352	543	550,093	$ 486,348.64	$ 22,182.07	$ 27,138.01	$ -	$ -
TN	365	17	110,771	$ 37,423.72	$ 14.10	$ 54.89	$ -	$ -
TN	371	85	1,064,383	$ 385,255.41	$ -	$ 23,249.91	$ -	$ -
TN	372	63	6,848,461	$ 405,219.31	$ -	$ 24,701.46	$ -	$ -
TN	373	1	353,198	$ 16,361.93	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTALS		**178,397**	**12,906,595**	**$ 6,826,506.82**	**$ 157,600.43**	**$ 342,800.30**	**$ -**	**$ -**

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Piedmont Natural Gas
August 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		75		$ 1,560.98	$ -	$ -	$ -	$ -
TN	301	160,741	1,690,490	$ 3,242,028.13	$ 8.35	$ 147,409.11	$ -	$ -
TN	302	16,400	1,677,616	$ 1,829,798.47	$ 121,130.98	$ 98,250.70	$ -	$ -
TN	311	1	-364	$ (221.65)	$ -	$ -	$ -	$ -
TN	331	48	407,660	$ 266,519.09	$ 12,633.35	$ 15,315.76	$ -	$ -
TN	341	2	12,853	$ 5,914.37	$ 140.02	$ 305.32	$ -	$ -
TN	352	545	533,928	$ 475,633.72	$ 21,638.74	$ 26,704.08	$ -	$ -
TN	365	20	61,495	$ 19,217.53	$ 17.37	$ 67.60	$ -	$ -
TN	371	81	1,122,602	$ 392,306.19	$ -	$ 23,674.96	$ -	$ -
TN	372	49	7,092,676	$ 421,620.18	$ -	$ 25,683.44	$ -	$ -
TN	373	1	384,055	$ 17,441.93	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTALS		**177,964**	**12,983,011**	**$ 6,672,534.85**	**$ 155,568.81**	**$ 337,410.97**	**$ -**	**$ -**

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Piedmont Natural Gas
September 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		76		$ 2,101.24	$ -	$ -	$ -	$ -
TN	301	160404	1,871,334	$ 3,354,691.71	$ (98.87)	$ 152,414.30	$ -	$ -
TN	302	16378	1,891,295	$ 1,967,534.26	$ 129,361.75	$ 106,160.42	$ -	$ -
TN	328	5	14,820	$ 4,456.37	$ -	$ 276.29	$ -	$ -
TN	331	46	398,898	$ 264,153.17	$ 12,390.05	$ 15,165.08	$ -	$ -
TN	341	2	21,385	$ 8,744.46	$ 218.86	$ 453.84	$ -	$ -
TN	352	546	598,572	$ 517,807.47	$ 23,219.78	$ 29,117.03	$ -	$ -
TN	365	19	85,807	$ 30,508.49	$ 6.96	$ 27.11	$ -	$ -
TN	371	81	1,138,472	$ 1,362,683.14	$ -	$ 72,210.67	$ -	$ -
TN	372	55	6,847,602	$ 415,588.03	$ -	$ 25,324.57	$ -	$ -
TN	373	1	363,826	$ 16,733.91	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN TOTALS		**177,614**	**13,232,011**	**$ 7,945,718.16**	**$ 165,098.53**	**$ 401,149.31**	**$ -**	**$ -**

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Piedmont Natural Gas
October 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		105		$ 2,265.65	$ -	$ -	$ -	$ -
TN	301	160,436	1,994,565	$ 3,836,826.33	$ 9.06	$ 174,599.14	$ -	$ -
TN	302	16,346	1,874,459	$ 2,142,707.87	$ 140,139.41	$ 115,956.14	$ -	$ -
TN	328	4		$ -	$ -	$ -	$ -	$ -
TN	331	47	433,564	$ 303,169.43	$ 13,054.40	$ 15,773.23	$ -	$ -
TN	341	2	21,764	$ 8,896.78	$ 296.42	$ 476.86	$ -	$ -
TN	352	552	673,787	$ 637,354.69	$ 28,882.33	$ 35,709.91	$ -	$ -
TN	365	20	61,578	$ 20,576.16	$ 16.73	$ 65.13	$ -	$ -
TN	371	82	1,315,095	$ 417,655.25	$ -	$ 25,203.24	$ -	$ -
TN	372	54	6,916,702	$ 421,185.50	$ -	$ 25,368.84	$ -	$ -
TN	373	1	395,686	$ 17,849.01	$ -	$ -	$ -	$ -
TN	381	1		$ 715.91	$ -	$ -	$ -	$ -
TN		**177,650**	**13,687,200**	**$ 7,809,202.58**	**$ 182,398.35**	**$ 393,152.49**	**$ -**	**$ -**

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Piedmont Natural Gas
November 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		79		$ 1,917.43	$ -	$ -	$ -	$ -
TN	301	161,209	3,986,061	$ 7,032,322.37	$ 16.60	$ 321,721.99	$ -	$ -
TN	302	16,668	2,552,763	$ 3,166,277.06	$ 202,407.67	$ 172,004.71	$ -	$ -
TN	313	1	6	$ 17.55	$ -	$ 1.09	$ -	$ -
TN	331	49	605,235	$ 348,849.45	$ 16,643.36	$ 19,561.17	$ -	$ -
TN	341	2	15,597	$ 7,003.58	$ 385.44	$ 406.53	$ -	$ -
TN	352	554	1,016,771	$ 1,093,622.63	$ 50,817.72	$ 60,593.86	$ -	$ -
TN	360	1	10,069,780	$ -	$ -	$ -	$ -	$ -
TN	365	19	46,528	$ 13,551.08	$ 18.40	$ 71.60	$ -	$ -
TN	371	88	1,680,140	$ 606,137.85	$ -	$ 26,371.46	$ -	$ -
TN	372	54	7,864,588	$ 459,560.61	$ -	$ 28,239.07	$ -	$ -
TN	373	1	525,089	$ 22,378.12	$ -	$ -	$ -	$ -
TN	381	1		$ 768.66	$ -	$ -	$ -	$ -
TN Total		**178,726**	**28,362,558**	**$ 12,752,406.39**	**$ 270,289.19**	**$ 628,971.48**	**$ -**	**$ -**

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Piedmont Natural Gas
December 2016 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		67		$ 1,802.40	$ -	$ -	$ -	$ -
TN	301	163,093	14,831,436	$ 14,954,683.78	$ 35.80	$ 685,147.36	$ -	$ -
TN	302	17,213	6,340,099	$ 6,070,592.72	$ 371,230.10	$ 329,240.80	$ -	$ -
TN	311	9	578	$ 522.93	$ -	$ 17.58	$ -	$ -
TN	313	3	97	$ 115.42	$ -	$ 3.51	$ -	$ -
TN	331	46	1,035,216	$ 595,551.24	$ 29,781.34	$ 31,676.05	$ -	$ -
TN	341	2	21,486	$ 10,817.80	$ 716.79	$ 652.80	$ -	$ -
TN	352	544	2,471,409	$ 2,189,626.99	$ 101,315.62	$ 119,933.46	$ -	$ -
TN	360	1	10,381,670	$ -	$ -	$ -	$ -	$ -
TN	365	18	62,022	$ 30,277.12	$ 20.43	$ 79.51	$ -	$ -
TN	371	92	2,291,947	$ 537,584.37	$ -	$ 32,304.51	$ -	$ -
TN	372	55	10,113,483	$ 540,541.13	$ -	$ 32,820.84	$ -	$ -
TN	373	1	737,581	$ 29,815.34	$ -	$ -	$ -	$ -
TN	381	1		$ 768.66	$ -	$ -	$ -	$ -
TN TOTAL		**181,145**	**48,287,024**	**$ 24,962,699.90**	**$ 503,100.08**	**$ 1,231,876.42**	**$ -**	**$ -**

Piedmont Natural Gas
January 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		92		$ (565.79)	$ -	$ -	$ -	$ -
TN	301	164,595	21,279,191	$ 21,959,630.56	$ 55.40	$ 974,940.94	$ -	$ -
TN	302	17,413	8,598,099	$ 8,689,349.14	$ 519,720.20	$ 464,047.96	$ -	$ -
TN	311	35	(578)	$ (522.93)	$ -	$ (17.58)	$ -	$ -
TN	313	13	(97)	$ (115.42)	$ -	$ (3.51)	$ -	$ -
TN	331	46	920,465	$ 552,947.90	$ 28,064.21	$ 29,775.37	$ -	$ -
TN	341	2	18,455	$ 9,568.06	$ 663.07	$ 583.35	$ -	$ -
TN	352	560	3,196,436	$ 3,070,094.73	$ 140,812.90	$ 167,624.98	$ -	$ -
TN	360	3	10,505,730	$ 31,500.00	$ -	$ -	$ -	$ -
TN	365	17	81,876	$ 29,457.35	$ 3.35	$ 13.03	$ -	$ -
TN	371	80	2,166,394	$ 545,752.37	$ -	$ 32,853.79	$ -	$ -
TN	372	49	9,970,739	$ 558,057.28	$ -	$ 33,803.82	$ -	$ -
TN	373	1	768,708	$ 30,904.78	$ -	$ -	$ -	$ -
TN	381	1		$ 768.66	$ -	$ -	$ -	$ -
TN TOTAL		**182,907**	**57,505,418**	**$ 35,476,826.69**	**$ 689,319.13**	**$ 1,703,622.15**	**$ -**	**$ -**

Piedmont Natural Gas
February 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		75		$ 2,014.14	$ -	$ -	$ -	$ -
TN	301	164,871	16,260,452	$ 18,766,495.50	$ 47.49	$ 831,498.23	$ -	$ -
TN	302	17,479	6,773,308	$ 7,500,610.38	$ 452,382.36	$ 397,159.54	$ -	$ -
TN	331	48	701,932	$ 453,340.05	$ 22,792.90	$ 24,754.64	$ -	$ -
TN	341	2	13,565	$ 7,475.00	$ 508.82	$ 453.85	$ -	$ -
TN	352	553	2,465,557	$ 2,601,405.99	$ 119,164.46	$ 143,554.41	$ -	$ -
TN	360	5	9,390,720	$ -	$ -	$ -	$ -	$ -
TN	365	17	9,244	$ 2,824.42	$ 32.06	$ 124.76	$ -	$ -
TN	371	81	1,808,625	$ 498,368.47	$ -	$ 29,998.89	$ -	$ -
TN	372	49	8,294,298	$ 486,581.78	$ -	$ 29,619.53	$ -	$ -
TN	373	1	668,393	$ 27,393.76	$ -	$ -	$ -	$ -
TN	381	4		$ 2,305.97	$ 114.28	$ 95.31	$ -	$ -
TN TOTAL		**183,185**	**46,386,094**	**$ 30,348,815.46**	**$ 595,042.37**	**$ 1,457,259.16**	**$ -**	**$ -**

Piedmont Natural Gas
March 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		66		$ 2,190.11	$ -	$ -	$ -	$ -
TN	301	165,452	12,163,554	$ 14,464,386.82	$ 36.17	$ 645,378.78	$ -	$ -
TN	302	17,488	5,313,493	$ 5,799,039.08	$ 354,942.83	$ 315,093.85	$ -	$ -
TN	331	49	761,463	$ 481,307.64	$ 25,090.35	$ 26,820.91	$ -	$ -
TN	341	2	17,323	$ 9,102.59	$ 523.99	$ 533.09	$ -	$ -
TN	352	564	1,980,929	$ 2,002,843.00	$ 91,406.88	$ 110,573.58	$ -	$ -
TN	360	1	10,402,360	$ 247,633.16	$ -	$ -	$ -	$ -
TN	365	16	133,406	$ 46,122.07	$ -	$ -	$ -	$ -
TN	371	85	1,845,664	$ 503,198.29	$ -	$ 30,300.84	$ -	$ -
TN	372	51	8,889,124	$ 519,312.38	$ -	$ 31,616.89	$ -	$ -
TN	373	3	680,227	$ 27,807.95	$ -	$ -	$ -	$ -
TN	381	8	99	$ 2,352.44	$ 114.09	$ 47.47	$ -	$ -
TN TOTAL		**183,785**	**42,187,642**	**$ 24,105,295.53**	**$ 472,114.31**	**$ 1,160,365.41**	**$ -**	**$ -**

Piedmont Natural Gas
April 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		72		$ 2,114.16	$ -	$ -	$ -	$ -
TN	301	166,262	8,308,094	$ 9,799,600.50	$ 24.18	$ 430,750.76	$ -	$ -
TN	302	17,317	3,798,685	$ 4,196,401.28	$ 258,954.02	$ 223,460.22	$ -	$ -
TN	311	1	14	$ 22.97	$ -	$ -	$ -	$ -
TN	331	49	459,601	$ 343,437.88	$ 13,106.80	$ 19,817.38	$ -	$ -
TN	341	2	20,539	$ 10,495.44	$ 363.89	$ 565.45	$ -	$ -
TN	352	561	1,410,424	$ 1,400,117.30	$ 62,210.96	$ 77,397.52	$ -	$ -
TN	360	1	4,576,500	$ -	$ -	$ -	$ -	$ -
TN	365	16	113,437	$ 42,749.20	$ 93.34	$ 86.94	$ -	$ -
TN	371	85	1,287,380	$ 432,028.58	$ -	$ 26,024.64	$ -	$ -
TN	372	49	7,241,218	$ 447,132.87	$ -	$ 27,255.91	$ -	$ -
TN	373	1	422,273	$ 18,779.56	$ -	$ -	$ -	$ -
TN	381	14	22	$ 2,314.65	$ (228.37)	$ (2.77)	$ -	$ -
TN TOTAL		**184,430**	**27,638,187**	**$ 16,695,194.39**	**$ 334,524.82**	**$ 805,356.05**	**$ -**	**$ -**

Piedmont Natural Gas
May 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		77		$ 2,363.82	$ -	$ -	$ -	$ -
TN	301	165858	3,466,722	$ 4,975,251.50	$ 42.18	$ 233,192.81	$ -	$ -
TN	302	17179	2,321,793	$ 2,627,518.26	$ 170,282.46	$ 148,945.88	$ -	$ -
TN	331	50	501,137	$ 365,238.10	$ 12,792.35	$ 22,581.18	$ -	$ -
TN	341	2	12,983	$ 7,260.46	$ 272.06	$ 406.15	$ -	$ -
TN	352	548	861,974	$ 821,716.60	$ 35,897.71	$ 48,608.80	$ -	$ -
TN	360	1	3,157,660	$ -	$ -	$ -	$ -	$ -
TN	365	19	19,295	$ 7,031.44	$ 31.74	$ 131.18	$ -	$ -
TN	371	81	1,237,083	$ 439,771.55	$ -	$ 28,162.71	$ -	$ -
TN	372	48	7,334,501	$ 470,954.14	$ -	$ 30,546.84	$ -	$ -
TN	373	1	417,770	$ 18,621.95	$ -	$ -	$ -	$ -
TN	381	2	11	$ 2,311.11	$ -	$ 46.27	$ -	$ -
TN Total		**183,866**	**19,330,929**	**$ 9,738,038.93**	**$ 219,318.50**	**$ 512,621.82**	**$ -**	**$ -**

Piedmont Natural Gas
June 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		58		$ 1,120.88	$ -	$ -	$ -	$ -
TN	301	164,910	2,536,235	$ 4,231,973.14	$ 7.95	$ 200,938.38	$ -	$ -
TN	302	16,985	2,133,039	$ 2,468,133.75	$ 162,414.78	$ 141,235.90	$ -	$ -
TN	331	46	331,278	$ 281,220.06	$ (23,355.36)	$ 17,107.91	$ -	$ -
TN	341	2	35,179	$ 16,790.59	$ 311.55	$ 852.41	$ -	$ -
TN	352	473	656,843	$ 636,550.51	$ 31,308.67	$ 37,912.44	$ -	$ -
TN	360	1	3,059,700	$ -	$ -	$ -	$ -	$ -
TN	365	4	24,101	$ 7,846.49	$ -	$ -	$ -	$ -
TN	371	79	1,246,882	$ 440,356.18	$ -	$ 28,251.10	$ -	$ -
TN	372	48	6,560,964	$ 432,906.45	$ -	$ 28,080.60	$ -	$ -
TN	373	1	349,716	$ 16,240.06	$ -	$ -	$ -	$ -
TN	381	2	44	$ 2,326.53	$ -	$ 46.74	$ -	$ -
TN TOTAL		**182,609**	**16,933,981**	**$ 8,535,464.64**	**$ 170,687.59**	**$ 454,425.48**	**$ -**	**$ -**

Piedmont Natural Gas
July 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		70		$ 816.41	$ -	$ -	$ -	$ -
TN	301	164,079	1,969,105	$ 3,769,106.58	$ 7.93	$ 179,990.90	$ -	$ -
TN	302	16,790	1,869,594	$ 2,247,384.60	$ 147,867.09	$ 127,983.10	$ -	$ -
TN	311	2	6	$ 29.75	$ -	$ 1.96	$ -	$ -
TN	328	2	38,898	$ 12,919.59	$ 964.15	$ 853.98	$ -	$ -
TN	331	45	309,448	$ 270,964.98	$ 11,729.55	$ 16,465.86	$ -	$ -
TN	341	2	4,265	$ 3,459.50	$ 101.59	$ 185.86	$ -	$ -
TN	352	466	590,459	$ 581,848.58	$ 27,856.49	$ 34,852.32	$ -	$ -
TN	360	4	3,116,780	$ -	$ -	$ -	$ -	$ -
TN	365	18	54,380	$ 17,343.95	$ 802.06	$ 1,091.01	$ -	$ -
TN	371	79	1,182,094	$ 431,382.42	$ -	$ 27,712.17	$ -	$ -
TN	372	52	6,424,316	$ 424,734.37	$ -	$ 27,551.75	$ -	$ -
TN	373	1	357,851	$ 16,524.79	$ -	$ -	$ -	$ -
TN	381	2	121	$ 2,362.52	$ -	$ 47.82	$ -	$ -
TN TOTAL		**181,612**	**15,917,317**	**$ 7,778,878.04**	**$ 189,328.86**	**$ 416,736.73**	**$ -**	**$ -**

Piedmont Natural Gas
August 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		68		$ 1,095.32	$ -	$ -	$ -	$ -
TN	301	164,112	1,758,698	$ 3,602,169.33	$ 7.77	$ 172,824.89	$ -	$ -
TN	302	16,737	1,913,710	$ 2,282,376.62	$ 151,548.43	$ 131,250.13	$ -	$ -
TN	311	1	7	$ 17.38	$ -	$ 1.15	$ -	$ -
TN	331	45	347,267	$ 288,694.07	$ 12,485.96	$ 17,629.72	$ -	$ -
TN	341	2	9,408	$ 5,701.79	$ 136.90	$ 297.97	$ -	$ -
TN	352	471	551,738	$ 550,254.54	$ 26,249.29	$ 33,218.55	$ -	$ -
TN	360	5	3,163,550	$ -	$ -	$ -	$ -	$ -
TN	365	21	142,957	$ 48,904.28	$ (772.40)	$ 2,128.07	$ -	$ -
TN	371	79	1,353,372	$ 451,887.02	$ -	$ 29,071.99	$ -	$ -
TN	372	48	5,886,748	$ 406,700.57	$ -	$ 26,320.81	$ -	$ -
TN	373	1	396,797	$ 17,887.90	$ -	$ -	$ -	$ -
TN	381	2	121	$ 2,362.52	$ -	$ 47.82	$ -	$ -
TN TOTAL		**181,592**	**15,524,373**	**$ 7,658,051.34**	**$ 189,655.95**	**$ 412,791.10**	**$ -**	**$ -**

Piedmont Natural Gas
September 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		86		$ 1,656.53	$ -	$ -	$ -	$ -
TN	301	163,606	2,078,890	$ 3,850,564.68	$ (16.42)	$ 184,521.42	$ -	$ -
TN	302	16,667	1,924,206	$ 2,287,066.88	$ 149,040.45	$ 130,472.12	$ -	$ -
TN	311	2	6	$ 29.76	$ -	$ 1.97	$ -	$ -
TN	331	45	343,338	$ 322,115.82	$ 12,576.65	$ 19,236.49	$ -	$ -
TN	341	2	11,283	$ 6,519.28	$ 263.93	$ 370.06	$ -	$ -
TN	352	515	644,794	$ 625,544.41	$ 28,403.01	$ 37,281.82	$ -	$ -
TN	360	1	3,061,500	$ -	$ -	$ -	$ -	$ -
TN	365	21	1,444	$ 527.15	$ -	$ -	$ -	$ -
TN	371	79	1,323,993	$ 451,178.34	$ -	$ 29,021.12	$ -	$ -
TN	372	48	5,772,541	$ 401,947.59	$ -	$ 26,026.96	$ -	$ -
TN	373	1	385,654	$ 17,497.89	$ -	$ -	$ -	$ -
TN	381	2	165	$ 2,383.08	$ -	$ 48.43	$ -	$ -
TN TOTALS		**181,075**	**15,547,814**	**$ 7,967,031.41**	**$ 190,267.62**	**$ 426,980.39**	**$ -**	**$ -**

Piedmont Natural Gas
October 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		96		$ 1,970.79	$ -	$ -	$ -	$ -
TN	301	163,778	2,232,778	$ 4,387,004.91	$ 8.22	$ 209,544.79	$ -	$ -
TN	302	16,751	2,061,359	$ 2,572,392.01	$ 167,874.20	$ 147,658.08	$ -	$ -
TN	311	1	6	$ 17.57	$ -	$ 1.16	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.86	$ -	$ -
TN	331	47	452,618	$ 338,306.99	$ 15,270.67	$ 20,431.16	$ -	$ -
TN	341	2	30,936	$ 15,043.13	$ 535.85	$ 833.89	$ -	$ -
TN	352	465	724,366	$ 752,569.21	$ 35,418.87	$ 45,082.13	$ -	$ -
TN	360	1	4,745,480	$ -	$ -	$ -	$ -	$ -
TN	365	16	337,896	$ 118,593.83	$ 343.05	$ 3,483.84	$ -	$ -
TN	371	80	1,664,158	$ 495,910.12	$ -	$ 31,842.16	$ -	$ -
TN	372	48	6,482,392	$ 439,349.84	$ -	$ 28,439.54	$ -	$ -
TN	373	1	461,687	$ 20,159.05	$ -	$ -	$ -	$ -
TN	381	2	551	$ 2,563.49	$ -	$ 53.85	$ -	$ -
TN TOTAL		**181,289**	**19,194,227**	**$ 9,143,893.94**	**$ 219,450.86**	**$ 487,371.46**	**$ -**	**$ -**

Piedmont Natural Gas
November 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		92		$ 2,163.70	$ -	$ -	$ -	$ -
TN	301	165,344	7,769,500	$ 9,719,025.04	$ 19.80	$ 473,096.48	$ -	$ -
TN	302	17,189	4,067,386	$ 4,370,660.05	$ 275,140.45	$ 252,875.92	$ -	$ -
TN	311	6	-23	$ (67.21)	$ -	$ (4.44)	$ -	$ -
TN	313	3	34	$ 37.07	$ -	$ 1.85	$ -	$ -
TN	331	47	679,225	$ 457,127.81	$ 21,934.60	$ 26,249.31	$ -	$ -
TN	341	2	40,811	$ 19,902.95	$ 740.92	$ 1,112.04	$ -	$ -
TN	352	460	1,511,620	$ 1,457,127.64	$ 69,317.29	$ 86,065.42	$ -	$ -
TN	360	1	300,000	$ 80,400.00	$ -	$ -	$ -	$ -
TN	365	19	17,441	$ 6,374.93	$ 11.41	$ 47.17	$ -	$ -
TN	371	78	2,017,437	$ 705,001.66	$ -	$ 43,052.07	$ -	$ -
TN	372	48	8,232,936	$ 514,934.45	$ -	$ 33,386.56	$ -	$ -
TN	373	1	659,937	$ 27,097.80	$ -	$ -	$ -	$ -
TN	381	2	1525	$ 3,096.32	$ -	$ 69.12	$ -	$ -
TN TOTAL		**183,292**	**25,297,829**	**$ 17,362,882.21**	**$ 367,164.47**	**$ 915,951.50**	**$ -**	**$ -**

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Piedmont Natural Gas
December 2017 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		87		$ 2,335.59	$ -	$ -	$ -	$ -
TN	301	166,631	16,119,520	$ 17,042,228.97	$ 32.24	$ 819,023.59	$ -	$ -
TN	302	17,459	6,830,906	$ 6,894,715.13	$ 419,247.71	$ 397,661.71	$ -	$ -
TN	313	1	78	$ 69.29	$ -	$ 3.46	$ -	$ -
TN	328	1	10193	$ 3,197.34	$ -	$ 211.34	$ -	$ -
TN	331	49	1,042,362	$ 628,814.43	$ 31,138.44	$ 34,559.01	$ -	$ -
TN	341	2	41,307	$ 20,116.05	$ 1,098.31	$ 1,219.50	$ -	$ -
TN	352	463	2,314,757	$ 2,176,345.38	$ 102,705.67	$ 128,579.05	$ -	$ -
TN	365	17	87,166	$ 31,428.92	$ 176.36	$ 728.99	$ -	$ -
TN	371	82	2,531,171	$ 618,387.16	$ -	$ 39,630.65	$ -	$ -
TN	372	48	9,648,299	$ 576,086.14	$ -	$ 37,359.37	$ -	$ -
TN	373	1	734,033	$ 29,691.16	$ -	$ -	$ -	$ -
TN	381	2	2,928	$ 3,772.42	$ -	$ 89.24	$ -	$ -
TN TOTAL		**184,843**	**39,362,720**	**$ 28,027,187.98**	**$ 554,398.73**	**$ 1,459,065.91**	**$ -**	**$ -**

Piedmont Natural Gas
January 2018 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		101		$ 2,551.71	$ -	$ -	$ -	$ -
TN	301	167,700	31,969,587	$ 29,285,342.65	$ 50.86	$ 1,401,979.33	$ -	$ -
TN	302	17,674	13,600,104	$ 12,218,026.84	$ 735,162.53	$ 701,716.86	$ -	$ -
TN	313	1	150	$ 112.75	$ -	$ 5.64	$ -	$ -
TN	328	5	115332	$ 40,238.89	$ 492.10	$ 2,659.80	$ -	$ -
TN	331	48	1,241,707	$ 726,055.67	$ 36,545.56	$ 39,174.04	$ -	$ -
TN	341	2	32,497	$ 16,113.32	$ 1,155.39	$ 1,052.21	$ -	$ -
TN	352	485	4,154,443	$ 3,595,477.13	$ 175,112.76	$ 208,752.72	$ -	$ -
TN	360	1	392,000	$ 113,548.00	$ -	$ -	$ -	$ -
TN	365	17	42,643	$ 15,896.45	$ 69.82	$ 288.62	$ -	$ -
TN	371	88	2,914,044	$ 663,649.35	$ -	$ 42,426.78	$ -	$ -
TN	372	54	10,698,211	$ 619,608.70	$ -	$ 40,155.32	$ -	$ -
TN	373	1	605,379	$ 25,188.27	$ -	$ -	$ -	$ -
TN	381	3	3,506	$ 4,050.96	$ -	$ 97.14	$ -	$ -
TN TOTALS		**186,180**	**65,769,603**	**$ 47,325,860.69**	**$ 948,589.02**	**$ 2,438,308.46**	**$ -**	**$ -**

Piedmont Natural Gas
February 2018 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		99		$ 2,302.24	$ -	$ -	$ -	$ -
TN	301	168,428	24,618,108	$ 24,860,377.16	$ 47.85	$ 1,147,662.81	$ -	$ -
TN	302	17,799	9,943,883	$ 9,887,451.80	$ 591,279.34	$ 552,891.99	$ -	$ -
TN	313	1	73	$ 70.50	$ -	$ 3.53	$ -	$ -
TN	328	4	17071	$ 6,363.72	$ 81.29	$ 420.64	$ -	$ -
TN	331	48	760,378	$ 526,894.49	$ 25,661.79	$ 30,163.10	$ -	$ -
TN	341	2	16,603	$ 9,068.46	$ 629.65	$ 586.55	$ -	$ -
TN	352	493	2,925,867	$ 2,776,093.80	$ 130,233.44	$ 162,800.35	$ -	$ -
TN	365	17	26,092	$ 7,739.67	$ 65.00	$ 511.59	$ -	$ -
TN	371	82	2,137,864	$ 565,181.73	$ -	$ 36,161.51	$ -	$ -
TN	372	52	8,377,781	$ 513,173.67	$ -	$ 33,241.10	$ -	$ -
TN	373	1	591,204	$ 24,692.14	$ -	$ -	$ -	$ -
TN	381	2	1,743	$ 3,201.37	$ -	$ 72.11	$ -	$ -
TN TOTAL		**187,028**	**49,416,667**	**$ 39,182,610.75**	**$ 747,998.36**	**$ 1,964,515.28**	**$ -**	**$ -**

Piedmont Natural Gas
March 2018 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		76		$ 2,223.13	$ -	$ -	$ -	$ -
TN	301	168,710	13,053,555	$ 15,843,017.95	$ 32.02	$ 742,736.77	$ -	$ -
TN	302	17,721	5,976,208	$ 6,623,109.68	$ 404,085.26	$ 375,525.74	$ -	$ -
TN	313	1	41	$ 44.74	$ -	$ 2.24	$ -	$ -
TN	328	5	51395	$ 16,096.65	$ 805.45	$ 1,063.99	$ -	$ -
TN	331	48	789,908	$ 505,406.19	$ 25,630.28	$ 28,905.45	$ -	$ -
TN	341	2	19,005	$ 10,136.19	$ 698.17	$ 654.06	$ -	$ -
TN	352	490	1,647,825	$ 1,759,156.02	$ 76,659.54	$ 102,790.20	$ -	$ -
TN	365	16		$ -	$ -	$ -	$ -	$ -
TN	371	88	2,247,228	$ 580,008.08	$ -	$ 37,100.39	$ -	$ -
TN	372	52	8,950,988	$ 542,965.47	$ -	$ 35,183.00	$ -	$ -
TN	373	1	666,519	$ 27,328.17	$ -	$ -	$ -	$ -
TN	381	2	1,707	$ 3,184.02	$ -	$ 71.75	$ -	$ -
TN TOTAL		**187,212**	**33,404,379**	**$ 25,912,676.29**	**$ 507,910.72**	**$ 1,324,033.59**	**$ -**	**$ -**

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Piedmont Natural Gas
April 2018 - 301C (Adjusted for Accruals)

	RATE	NUMBER TRANS	THERMS	REVENUE W/O TAX	STATE	CITY	EXCISE TAX	OTHER
TN		73		$ 1,841.98	$ -	$ -	$ -	$ -
TN	301	168716	12,942,537	$ 12,498,769.94	$ 27.99	$ 583,802.11	$ -	$ -
TN	302	17658	5,716,112	$ 5,362,113.54	$ 328,103.70	$ 304,153.03	$ -	$ -
TN	313	1	31	$ 31.77	$ -	$ 1.59	$ -	$ -
TN	328	2	34,280	$ 10,064.14	$ -	$ 665.24	$ -	$ -
TN	331	51	627,950	$ 444,631.19	$ 21,504.25	$ 26,244.90	$ -	$ -
TN	341	2	16,468	$ 9,019.33	$ 541.31	$ 560.14	$ -	$ -
TN	352	467	1,902,079	$ 1,629,334.94	$ 74,868.78	$ 97,408.76	$ -	$ -
TN	365	14	151,028	$ 50,392.68	$ 25.14	$ 2,017.80	$ -	$ -
TN	371	84	1,973,109	$ 543,081.66	$ -	$ 34,760.82	$ -	$ -
TN	372	48	8,520,974	$ 528,226.34	$ -	$ 34,230.40	$ -	$ -
TN	373	1	526,413	$ 22,424.46	$ -	$ -	$ -	$ -
TN	381	2	1,185	$ 2,932.47	$ -	$ 64.36	$ -	$ -
TN TOTAL		**187119**	**32,412,166**	**$ 21,102,864.44**	**$ 425,071.17**	**$ 1,083,909.15**	**$ -**	**$ -**

Piedmont Natural Gas
May 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		57		$ 1,701.68	$ -	$ -	$ -	$ -
TN	301	168,947	6,268,071	$ 7,367,358.09	$ 36.56	$ 332,755.25	$ -	$ -
TN	302	17,571	3,315,230	$ 3,511,577.01	$ 221,267.70	$ 193,414.10	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.65	$ -	$ -
TN	331	45	350099	$ 309,620.39	$ 13,927.92	$ 18,589.61	$ -	$ -
TN	341	2	20,600	$ 10,847.20	$ 243.65	$ 560.45	$ -	$ -
TN	352	506	1,077,981	$ 997,321.50	$ 46,004.02	$ 57,528.69	$ -	$ -
TN	365	19	14,471	$ 4,801.65	$ -	$ 136.94	$ -	$ -
TN	371	84	1,410,167	$ 463,863.07	$ -	$ 29,089.66	$ -	$ -
TN	372	50	7,209,857	$ 461,334.80	$ -	$ 29,248.21	$ -	$ -
TN	373	1	428,429	$ 18,995.02	$ -	$ -	$ -	$ -
TN	381	2	431	$ 2,569.12	$ -	$ 53.46	$ -	$ -
TN TOTAL		**187,285**	**20,095,336**	**$ 13,150,002.53**	**$ 281,479.85**	**$ 661,377.02**	**$ -**	**$ -**

Piedmont Natural Gas
June 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		56		$ 1,712.60	$ -	$ -	$ -	$ -
TN	301	167,999	2,290,562	$ 4,186,678.08	$ 12.43	$ 195,157.21	$ -	$ -
TN	302	17,222	2,104,321	$ 2,549,356.77	$ 165,973.20	$ 142,954.89	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.65	$ -	$ -
TN	331	46	320880	$ 303,075.86	$ 14,084.53	$ 18,020.09	$ -	$ -
TN	341	2	37,443	$ 18,411.92	$ 337.01	$ 932.28	$ -	$ -
TN	352	484	658,030	$ 664,999.12	$ 28,044.60	$ 39,483.67	$ -	$ -
TN	360	1	420,000	$ 117,510.00	$ -	$ -	$ -	$ -
TN	365	18	54,307	$ 18,979.06	$ -	$ 1,159.29	$ -	$ -
TN	371	86	1,288,660	$ 485,352.47	$ -	$ 30,429.96	$ -	$ -
TN	372	50	6,528,899	$ 446,045.26	$ -	$ 28,278.10	$ -	$ -
TN	373	1	409,368	$ 18,327.88	$ -	$ -	$ -	$ -
TN	381	2	274	$ 2,496.58	$ -	$ 51.28	$ -	$ -
TN TOTAL		**185,968**	**14,112,744**	**$ 8,812,958.60**	**$ 208,451.77**	**$ 456,467.42**	**$ -**	**$ -**

Piedmont Natural Gas
July 2018 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		60		$ (2,368.22)	$ -	$ -	$ -	$ -
TN	301	167,402	1,827,276	$ 3,788,317.40	$ 9.22	$ 177,805.45	$ -	$ -
TN	302	17,053	1,821,263	$ 2,299,622.37	$ 154,803.13	$ 128,190.41	$ -	$ -
TN	311	1		$ -	$ -	$ -	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.65	$ -	$ -
TN	331	47	319,927	$ 302,597.67	$ 13,749.43	$ 17,780.85	$ -	$ -
TN	341	2	5,241	$ 3,976.11	$ 109.64	$ 210.49	$ -	$ -
TN	352	465	558,673	$ 579,979.81	$ 26,980.20	$ 33,933.87	$ -	$ -
TN	365	22	22,908	$ 7,072.31	$ 91.93	$ 344.32	$ -	$ -
TN	371	86	1,214,362	$ 475,643.70	$ -	$ 29,826.70	$ -	$ -
TN	372	50	6,745,893	$ 457,203.13	$ -	$ 29,016.05	$ -	$ -
TN	373	1	369,509	$ 16,932.82	$ -	$ -	$ -	$ -
TN	381	2	264	$ 2,491.65	$ -	$ 51.14	$ -	$ -
TN TOTAL		**185,192**	**12,885,316**	**$ 7,931,481.75**	**$ 195,743.55**	**$ 417,159.93**	**$ -**	**$ -**

Piedmont Natural Gas
August 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		50		$ 1,627.20	$ -	$ -	$ -	$ -
TN	301	167,960	1,719,601	$ 3,697,308.99	$ 9.43	$ 173,967.23	$ -	$ -
TN	302	17,092	1,833,630	$ 2,305,463.76	$ 152,371.28	$ 128,942.50	$ -	$ -
TN	311	1		$ -	$ -	$ (0.84)	$ -	$ -
TN	313	1		$ 13.00	$ -	$ 0.65	$ -	$ -
TN	331	46	348,242	$ 314,871.37	$ 14,958.09	$ 18,983.41	$ -	$ -
TN	341	2	8,988	$ 5,674.89	$ 136.40	$ 295.42	$ -	$ -
TN	352	472	540,671	$ 565,146.03	$ 26,338.55	$ 33,362.93	$ -	$ -
TN	365	20	8,237	$ 2,617.56	$ -	$ 164.17	$ -	$ -
TN	371	78	1,353,885	$ 493,572.27	$ -	$ 30,952.31	$ -	$ -
TN	372	48	6,783,164	$ 460,604.39	$ -	$ 29,219.51	$ -	$ -
TN	373	1	434,024	$ 19,190.84	$ -	$ -	$ -	$ -
TN	381	2	297	$ 2,507.92	$ -	$ 51.63	$ -	$ -
TN TOTAL		**185,773**	**13,030,739**	**$ 7,868,598.22**	**$ 193,813.75**	**$ 415,938.92**	**$ -**	**$ -**

Piedmont Natural Gas
September 2018 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		42		$ 1,545.71	$ -	$ -	$ -	$ -
TN	301	166,696	1,950,743	$ 3,880,128.93	$ 114.10	$ 181,462.22	$ -	$ -
TN	302	16,970	2,006,548	$ 2,448,412.96	$ 160,456.77	$ 136,912.11	$ -	$ -
TN	311	1		$ -	$ -	$ -	$ -	$ -
TN	313	10	-407	$ (418.12)	$ -	$ (20.91)	$ -	$ -
TN	331	51	348,371	$ 337,108.43	$ 15,438.30	$ 19,998.27	$ -	$ -
TN	341	2	25,931	$ 13,290.60	$ 307.32	$ 688.88	$ -	$ -
TN	352	459	586,696	$ 601,891.91	$ 26,782.17	$ 35,127.81	$ -	$ -
TN	360	1	310,000	$ 88,340.00	$ -	$ -	$ -	$ -
TN	365	18	31,506	$ 10,152.15	$ -	$ 416.85	$ -	$ -
TN	371	78	1,279,750	$ 486,277.77	$ -	$ 30,511.62	$ -	$ -
TN	372	50	6,392,156	$ 442,828.27	$ -	$ 28,090.48	$ -	$ -
TN	373	1	425,961	$ 18,908.64	$ -	$ -	$ -	$ -
TN	381	4	349	$ 2,533.57	$ -	$ 52.39	$ -	$ -
TN TOTAL		**184,383**	**13,357,604**	**$ 8,331,000.82**	**$ 203,098.66**	**$ 433,239.72**	**$ -**	**$ -**

Piedmont Natural Gas
October 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		22		$ 1,007.01	$ -	$ -	$ -	$ -
TN	301	167,004	2,415,758	$ 4,533,044.37	$ 15.53	$ 214,423.69	$ -	$ -
TN	302	17,044	2,179,791	$ 2,690,164.68	$ 174,110.87	$ 151,213.28	$ -	$ -
TN	311	1		$ -	$ -	$ (0.84)	$ -	$ -
TN	313	3	-217	$ (202.47)	$ -	$ (12.47)	$ -	$ -
TN	328	2	15,102	$ 4,352.12	$ -	$ 281.15	$ -	$ -
TN	331	54	666,314	$ 473,925.62	$ 20,851.13	$ 28,346.50	$ -	$ -
TN	341	2	36,189	$ 17,928.57	$ 607.28	$ 977.14	$ -	$ -
TN	352	472	700,139	$ 733,389.61	$ 32,974.95	$ 42,988.02	$ -	$ -
TN	365	19	112,585	$ 38,915.79	$ 95.57	$ 1,388.59	$ -	$ -
TN	371	83	1,745,897	$ 557,922.16	$ -	$ 34,988.38	$ -	$ -
TN	372	50	7,939,000	$ 524,370.90	$ -	$ 33,268.14	$ -	$ -
TN	373	1	564,468	$ 23,756.38	$ -	$ -	$ -	$ -
TN	381	2	857	$ 2,784.16	$ -	$ 59.91	$ -	$ -
TN TOTAL		**184,759**	**16,375,883**	**$ 9,601,358.90**	**$ 228,655.33**	**$ 507,921.49**	**$ -**	**$ -**

Piedmont Natural Gas
November 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		22		$ 1,022.07	$ -	$ -	$ -	$ -
TN	301	168,580	10,307,018	$ 11,261,630.40	$ 35.88	$ 537,479.26	$ -	$ -
TN	302	17,505	5,194,641	$ 5,043,027.18	$ 315,827.76	$ 284,990.10	$ -	$ -
TN	328	2	0	$ -	$ -	$ -	$ -	$ -
TN	331	54	847860	$ 538,645.47	$ 30,078.17	$ 29,308.72	$ -	$ -
TN	341	2	38,910	$ 18,139.88	$ 881.75	$ 1,055.06	$ -	$ -
TN	352	462	1,732,505	$ 1,529,800.20	$ 69,997.50	$ 87,343.07	$ -	$ -
TN	365	22	82,700	$ 42,192.69	$ 56.29	$ 694.35	$ -	$ -
TN	371	85	2,327,825	$ 782,344.75	$ -	$ 47,027.92	$ -	$ -
TN	372	53	9,295,101	$ 589,655.83	$ -	$ 37,424.42	$ -	$ -
TN	373	3	743,497	$ 30,022.40	$ -	$ -	$ -	$ -
TN	381	2	2,826	$ 3,498.76	$ -	$ 83.16	$ -	$ -
TN TOTAL		**186,792**	**30,572,883**	**$ 19,839,979.63**	**$ 416,877.35**	**$ 1,025,406.06**	**$ -**	**$ -**

Piedmont Natural Gas
December 2018 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		24		$ 1,044.60	$ -	$ -	$ -	$ -
TN	301	169,929	19,992,349	$ 19,714,070.20	$ 53.63	$ 919,800.44	$ -	$ (2.00)
TN	302	17,730	8,557,208	$ 8,160,096.61	$ 494,662.03	$ 456,180.92	$ -	$ -
TN	311	2		$ -	$ -	$ -	$ -	$ -
TN	331	49	1048059	$ 634,521.28	$ 33,649.09	$ 34,550.69	$ -	$ -
TN	341	2	27,269	$ 13,191.79	$ 784.05	$ 802.75	$ -	$ -
TN	352	460	2,627,974	$ 2,368,343.47	$ 109,130.91	$ 135,072.24	$ -	$ -
TN	365	22	8,796	$ 5,100.99	$ 11.25	$ 45.49	$ -	$ -
TN	371	79	2,479,428	$ 647,026.39	$ -	$ 40,570.18	$ -	$ -
TN	372	49	9,644,638	$ 605,596.89	$ -	$ 38,456.95	$ -	$ -
TN	373	1	787,698	$ 31,569.43	$ -	$ -	$ -	$ -
TN	381	2	3,181	$ 3,664.43	$ -	$ 88.13	$ -	$ -
TN TOTAL		**188,349**	**45,176,600**	**$ 32,184,226.08**	**$ 638,290.96**	**$ 1,625,567.79**	**$ -**	**$ (2.00)**

Piedmont Natural Gas
January 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		23		$ 1,055.67	$ -	$ -	$ -	$ -
TN	301	170,965	21,062,323	$ 22,779,201.32	$ 59.95	$ 1,054,534.52	$ -	$ -
TN	302	17,961	9,393,889	$ 9,678,167.34	$ 589,644.03	$ 540,226.22	$ -	$ -
TN	331	55	1152734	$ 683,748.29	$ 36,999.42	$ 37,787.43	$ -	$ -
TN	341	2	26745	$ 12,927.81	$ 916.39	$ 823.46	$ -	$ -
TN	352	492	2,835,711	$ 2,803,108.52	$ 130,204.84	$ 160,914.70	$ -	$ -
TN	365	18	52,315	$ 19,355.78	$ 92.71	$ 375.06	$ -	$ -
TN	371	79	2,778,368	$ 685,457.16	$ -	$ 42,904.91	$ -	$ -
TN	372	49	10,402,401	$ 639,142.11	$ -	$ 40,515.32	$ -	$ -
TN	373	1	766,201	$ 30,817.04	$ -	$ -	$ -	$ -
TN	381	2	4,033	$ 4,062.02	$ -	$ 100.06	$ -	$ -
TN TOTAL		**189,647**	**48,474,720**	**$ 37,337,043.06**	**$ 757,917.34**	**$ 1,878,181.68**	**$ -**	**$ -**

Piedmont Natural Gas
February 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		21		$ 1,064.95	$ -	$ -	$ -	$ -
TN	301	171,009	23,389,331	$ 24,284,331.98	$ 56.91	$ 1,120,606.15	$ -	$ -
TN	302	17,855	9,672,283	$ 9,753,380.85	$ 586,033.91	$ 540,373.07	$ -	$ -
TN	331	49	875099	$ 552,663.18	$ 29,236.24	$ 30,868.89	$ -	$ -
TN	341	2	16843	$ 8,774.31	$ 606.86	$ 555.14	$ -	$ -
TN	352	491	2,887,417	$ 2,785,425.77	$ 128,793.30	$ 159,619.55	$ -	$ -
TN	365	19	98,563	$ 32,700.03	$ 21.65	$ 2,048.40	$ -	$ -
TN	371	79	2,134,310	$ 598,620.14	$ -	$ 37,501.70	$ -	$ -
TN	372	49	8,724,223	$ 558,108.32	$ -	$ 35,411.03	$ -	$ -
TN	373	1	661,097	$ 27,138.40	$ -	$ -	$ -	$ -
TN	381	3	2,482	$ 3,338.23	$ -	$ 78.35	$ -	$ -
TN TOTAL		**189,578**	**48,461,648**	**$ 38,605,546.16**	**$ 744,748.87**	**$ 1,927,062.28**	**$ -**	**$ -**

Piedmont Natural Gas
March 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		21		$ 916.92				
TN	301	171,493	18,029,455	$ 18,824,076.09	$ 42.93	$ 862,374.82	$ -	$ -
TN	302	17,886	7,854,945	$ 7,730,823.17	$ 468,967.38	$ 427,865.08	$ -	$ -
TN	331	47	913701	$ 567,886.62	$ 28,947.88	$ 32,154.94	$ -	$ -
TN	341	3	17383	$ 9,818.19	$ 682.22	$ 621.97	$ -	$ -
TN	352	477	2,353,919	$ 2,167,899.00	$ 98,495.03	$ 124,879.71	$ -	$ -
TN	365	20	10,843	$ 3,614.09	$ 9.26	$ 8.03	$ -	$ -
TN	371	79	2,285,313	$ 618,572.23	$ -	$ 38,723.37	$ -	$ -
TN	372	49	9,423,223	$ 598,529.41	$ -	$ 37,992.34	$ -	$ -
TN	373	1	681,758	$ 27,861.53	$ -	$ -	$ -	$ -
TN	381	3	2,641	$ 3,412.43	$ -	$ 80.57	$ -	$ -
TN TOTAL		**190,079**	**41,573,181**	**$ 30,553,409.68**	**$ 597,144.70**	**$ 1,524,700.83**	**$ -**	**$ -**

Piedmont Natural Gas
April 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		24		$ 935.85	$ -	$ -	$ -	$ -
TN	301	171,506	10,706,784	$ 11,227,740.93	$ 27.77	$ 506,845.16	$ -	$ -
TN	302	17,917	5,097,326	$ 5,095,562.45	$ 313,664.06	$ 279,642.79	$ -	$ -
TN	331	48	528974	$ 389,432.87	$ 18,937.13	$ 23,169.08	$ -	$ -
TN	341	2	13788	$ 7,484.03	$ 375.02	$ 438.09	$ -	$ -
TN	352	463	1,520,145	$ 1,402,147.98	$ 63,218.59	$ 81,227.86	$ -	$ -
TN	365	19	5,693	$ 1,610.83	$ 22.42	$ 89.49	$ -	$ -
TN	371	80	1,666,596	$ 526,089.78	$ -	$ 33,011.27	$ -	$ -
TN	372	49	7,319,432	$ 499,864.65	$ -	$ 31,704.60	$ -	$ -
TN	373	1	519,805	$ 22,193.18	$ -	$ -	$ -	$ -
TN	381	3	977	$ 2,635.91	$ -	$ 57.28	$ -	$ -
TN TOTAL		**190,112**	**27,379,520**	**$ 19,175,698.46**	**$ 396,244.99**	**$ 956,185.62**	**$ -**	**$ -**

Piedmont Natural Gas
May 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		23		$ 953.42	$ -	$ -	$ -	$ -
TN	301	171,225	4,180,337	$ 5,685,421.13	$ 15.02	$ 241,874.66	$ -	$ -
TN	302	17,568	2,719,260	$ 2,996,431.96	$ 190,691.36	$ 154,053.49	$ -	$ -
TN	311	2		$ -	$ -	$ -	$ -	$ -
TN	331	48	420266	$ 338,121.44	$ 15,776.25	$ 18,944.08	$ -	$ -
TN	341	2	9,094	$ 5,480.87	$ 230.75	$ 299.24	$ -	$ -
TN	352	481	846,135	$ 799,340.59	$ 34,690.83	$ 43,566.68	$ -	$ -
TN	360	1	410,000	$ 98,695.00	$ -	$ -	$ -	$ -
TN	365	19	31,972	$ 8,942.89	$ 52.46	$ 274.08	$ -	$ -
TN	371	78	1,449,858	$ 491,613.88	$ -	$ 28,848.26	$ -	$ -
TN	372	49	6,903,342	$ 472,327.79	$ -	$ 27,989.98	$ -	$ -
TN	373	1	449,306	$ 19,725.71	$ -	$ -	$ -	$ -
TN	381	3	553	$ 2,438.04	$ -	$ 51.34	$ -	$ -
TN TOTAL		**189,500**	**17,420,123**	**$ 10,919,492.72**	**$ 241,456.67**	**$ 515,901.81**	**$ -**	**$ -**

Piedmont Natural Gas
June 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		23		$ (9,552.54)				$ -
TN	301	170,611	2,502,052	$ 4,049,768.61	$ 11.98	$ 176,668.47	$ -	$ -
TN	302	17,188	2,129,356	$ 2,308,642.01	$ 151,212.92	$ 121,506.93	$ -	$ -
TN	331	53	373527	$ 305,816.23	$ 14,547.89	$ 17,071.05	$ -	$ -
TN	341	2	12359	$ 6,672.63	$ 151.86	$ 341.79	$ -	$ -
TN	352	570	724,819	$ 655,049.77	$ 29,211.00	$ 35,209.35	$ -	$ -
TN	360	2	0	$ -	$ -		$ -	$ -
TN	365	19	18,988	$ 5,090.82	$ 28.76	$ 82.28	$ -	$ -
TN	371	77	1,316,898	$ 421,955.01	$ -	$ 24,723.24	$ -	$ -
TN	372	49	6,483,854	$ 339,753.81	$ -	$ 20,085.62	$ -	$ -
TN	373	1	424,497	$ 18,857.40	$ -	$ -	$ -	$ -
TN	381	2	500	$ 2,387.81	$ -	$ 49.83	$ -	$ -
TN TOTAL		**188,597**	**13,986,850**	**$ 8,104,441.56**	**$ 195,164.41**	**$ 395,738.56**	**$ -**	**$ -**

Piedmont Natural Gas
July 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		19		$ 814.96	$ -	$ -	$ -	$ -
TN	301	170,795	2,012,046	$ 3,699,852.27	$ 69.60	$ 163,698.02	$ -	$ -
TN	302	17,104	1,982,692	$ 2,187,251.57	$ 143,402.16	$ 114,962.71	$ -	$ -
TN	331	56	375472	$ 309,519.45	$ 14,759.18	$ 17,277.82	$ -	$ -
TN	341	2	9547	$ 5,518.47	$ 133.69	$ 284.08	$ -	$ -
TN	352	574	688,824	$ 629,613.48	$ 28,687.46	$ 34,111.61	$ -	$ -
TN	365	21	20,674	$ 5,234.90	$ 16.27	$ 309.56	$ -	$ -
TN	371	88	1,266,291	$ 412,900.94	$ -	$ 24,166.22	$ -	$ -
TN	372	53	6,729,793	$ 350,474.30	$ -	$ 20,741.73	$ -	$ -
TN	373	1	348,205	$ 16,187.18	$ -	$ -	$ -	$ -
TN	381	2	675	$ 2,460.54	$ -	$ 52.02	$ -	$ -
TN TOTAL		**188,715**	**13,434,219**	**$ 7,619,828.06**	**$ 187,068.36**	**$ 375,603.77**	**$ -**	**$ -**

Piedmont Natural Gas
August 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN	301	170,242	1853321	$ 3,588,414.90	$ 12.50	$ 158,667.95	$ -	$ -
TN	302	17,037	1,856,635	$ 2,093,682.14	$ 139,653.13	$ 109,831.20	$ -	$ -
TN	331	52	396,637	$ 318,972.26	$ 15,224.30	$ 17,844.95	$ -	$ -
TN	341	2	2845	$ 2,767.70	$ 91.12	$ 146.68	$ -	$ -
TN	352	572	628147	$ 583,898.26	$ 26,174.13	$ 31,437.35	$ -	$ -
TN	365	4	19,954	$ 4,974.61	$ 73.47	$ 221.99	$ -	$ -
TN	371	76	1,319,440	$ 418,462.99	$ -	$ 24,498.19	$ -	$ -
TN	372	49	6,599,181	$ 347,570.91	$ -	$ 20,560.54	$ -	$ -
TN	373	1	410,032	$ 18,351.12	$ -	$ -	$ -	$ -
TN	381	2	751	$ 2,492.13	$ -	$ 52.96	$ -	$ -
TN TOTAL		**188,037**	**13,086,943**	**$ 7,379,587.02**	**$ 181,228.65**	**$ 363,261.81**	**$ -**	**$ -**

Piedmont Natural Gas
September 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN		19		$ 839.59				
TN	301	169,785	1,957,164	$ 3,657,292.86	$ 12.65	$ 161,029.17	$ -	$ -
TN	302	17,013	1,934,048	$ 2,145,560.15	$ 140,581.22	$ 112,253.65	$ -	$ -
TN	331	53	379108	$ 326,211.64	$ 14,973.41	$ 18,114.98	$ -	$ -
TN	341	2	29494	$ 13,600.39	$ 262.75	$ 688.49	$ -	$ -
TN	352	583	668,510	$ 605,705.39	$ 26,685.67	$ 32,551.16	$ -	$ -
TN	360	1	660,000	$ 142,090.00	$ -	$ -	$ -	$ -
TN	365	20	10,976	$ 2,905.68	$ -	$ -	$ -	$ -
TN	371	78	1,193,145	$ 404,310.94	$ -	$ 23,697.10	$ -	$ -
TN	372	49	6,313,711	$ 335,721.44	$ -	$ 19,861.52	$ -	$ -
TN	373	1	385,303	$ 17,485.61	$ -	$ -	$ -	$ -
TN	381	2	762	$ 2,496.71	$ -	$ 53.10	$ -	$ -
TN TOTAL		**187,606**	**13,532,221**	**$ 7,654,220.40**	**$ 182,515.70**	**$ 368,249.17**	**$ -**	**$ -**

Piedmont Natural Gas
October 2019 - 301C (Adjusted for Accruals)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
		19		$ 849.65				
TN	301	170,237	2,335,813	$ 4,224,796.50	$ 13.55	$ 186,989.28		$ -
TN	302	17,068	2,141,128	$ 2,426,843.29	$ 157,472.97	$ 128,529.36		$ -
TN	331	53	545604	$ 387,712.66	$ 18,870.48	$ 21,704.58		$ -
TN	341	2	31419	$ 14,469.37	$ 719.46	$ 809.23		$ -
TN	352	575	773,300	$ 745,845.41	$ 33,351.04	$ 40,156.54		$ -
TN	365	17	158,255	$ 41,913.34	$ 69.85	$ 1,629.86		$ -
TN	371	76	1,645,653	$ 461,070.84	$ -	$ 26,997.19		$ -
TN	372	49	7,476,037	$ 384,540.53	$ -	$ 22,747.12		$ -
TN	373	1	502,424	$ 21,584.84	$ -	$ -		$ -
TN	381	2	1,449	$ 2,782.26	$ -	$ 61.67		$ -
TN TOTAL		**188,099**	**15,611,082**	**$ 8,712,408.69**	**$ 210,497.35**	**$ 429,624.83**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
November 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
		19		$ 861.64				
TN	301	171,236	10,086,725	$ 10,220,017.21	$ 30.78	$ 459,867.73	$ -	$ -
TN	302	17,436	4,731,896	$ 4,301,290.19	$ 269,459.76	$ 229,032.92	$ -	$ -
TN	331	59	1001954	$ 610,870.02	$ 31,509.54	$ 31,440.16	$ -	$ -
TN	341	2	34525	$ 16,478.93	$ 982.48	$ 950.07	$ -	$ -
TN	352	572	1,999,097	$ 1,617,883.20	$ 76,308.92	$ 84,728.05	$ -	$ -
TN	365	20	15,643	$ 4,484.56	$ 15.15	$ 237.28	$ -	$ -
TN	371	85	2,112,075	$ 665,679.59	$ -	$ 37,646.39	$ -	$ -
TN	372	57	9,173,575	$ 437,060.86	$ -	$ 25,868.74	$ -	$ -
TN	373	1	606,656	$ 25,232.96	$ -	$ -	$ -	$ -
TN	381	2	4,918	$ 4,221.61	$ -	$ 106.00	$ -	$ -
TN TOTAL		**189,489**	**29,767,064**	**$ 17,904,080.77**	**$ 378,306.63**	**$ 869,877.34**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
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Piedmont Natural Gas
December 2019 - 301C (Adjusted for Accruals & CNG)

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
		19		$ 876.96				
TN	301	172,736	18,333,507	$ 17,344,605.81	$ 56.14	$ 761,939.93	$ -	$ -
TN	302	17,810	7,591,560	$ 7,011,010.62	$ 427,309.12	$ 370,572.12	$ -	$ -
TN	331	53	1000316	$ 610,349.48	$ 31,361.32	$ 30,854.30	$ -	$ -
TN	341	2	34024	$ 16,259.78	$ 985.83	$ 940.31	$ -	$ -
TN	352	603	2,969,799	$ 2,584,230.86	$ 123,592.00	$ 135,028.31	$ -	$ -
TN	365	24	84,944	$ 26,574.93	$ 22.12	$ 1,599.81	$ -	$ -
TN	371	79	2,174,730	$ 517,943.32	$ -	$ 30,285.38	$ -	$ -
TN	372	49	9,182,855	$ 433,897.22	$ -	$ 25,679.71	$ -	$ -
TN	373	1	618,597	$ 25,650.90	$ -	$ -	$ -	$ -
TN	381	2	5,103	$ 4,302.76	$ -	$ 108.44	$ -	$ -
TN TOTAL		**191,378**	**41,995,435**	**$ 28,575,702.64**	**$ 583,326.53**	**$ 1,357,008.31**	**$ -**	**$ -**

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Piedmont Natural Gas
January 2020 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
		18		$ 886.45	$ -	$ -	$ -	$ -
TN	301	173,507	19,309,797	$ 20,864,347.81	$ 48.21	$ 910,651.95	$ -	$ -
TN	302	17,769	8,192,387	$ 8,503,762.12	$ 520,821.27	$ 447,895.95	$ -	$ -
TN	328	3	36429	$ 9,026.82	$ 559.82	$ 543.42	$ -	$ -
TN	331	60	1108623	$ 656,334.41	$ 33,923.81	$ 33,414.75	$ -	$ -
TN	341	2	28,722	$ 13,950.33	$ 987.71	$ 831.51	$ -	$ -
TN	352	572	3,067,387	$ 3,022,574.40	$ 143,834.23	$ 158,249.80	$ -	$ -
TN	365	15	38,125	$ 8,446.21	$ 62.98	$ 434.16	$ -	$ -
TN	371	81	2,351,629	$ 540,859.76	$ -	$ 31,608.11	$ -	$ -
TN	372	53	9,733,151	$ 448,835.68	$ -	$ 26,554.73	$ -	$ -
TN	373	1	691,473	$ 28,201.56	$ -	$ -	$ -	$ -
TN	381	2	6,129	$ 4,752.85	$ -	$ 121.94	$ -	$ -
TN TOTAL		**192,083**	**44,563,852**	**$ 34,101,978.40**	**$ 700,238.03**	**$ 1,610,306.32**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

Piedmont Natural Gas
February 2020 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN	301	173,864	21228260	$ 21,350,515.89	$ 52.35	$ 912,958.37	$ -	$ -
TN	302	17,905	8,638,174	$ 8,410,916.10	$ 510,195.54	$ 436,630.55	$ -	$ -
TN	328	-	0	$ -	$ -	$ -	$ -	$ -
TN	331	52	1082117	$ 643,699.99	$ 33,258.23	$ 32,671.08	$ -	$ -
TN	341	2	29104	$ 14,112.89	$ 1,000.60	$ 841.44	$ -	$ -
TN	352	644	3,240,841	$ 2,984,021.13	$ 141,015.61	$ 154,260.58	$ -	$ -
TN	365	19	84,681	$ 18,333.10	$ 7.40	$ 28.01	$ -	$ -
TN	371	83	2,308,015	$ 534,404.44	$ -	$ 31,231.13	$ -	$ -
TN	372	51	9,284,253	$ 433,666.38	$ -	$ 25,665.67	$ -	$ -
TN	373	1	601,926	$ 25,067.41	$ -	$ -	$ -	$ -
TN	381	2	5,895	$ 4,650.20	$ -	$ 118.86	$ -	$ -
TN TOTAL		**192,623**	**46,503,266**	**$ 34,419,387.53**	**$ 685,529.73**	**$ 1,594,405.69**	**$ -**	**$ -**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 14 Attachment 2 of 2

Piedmont Natural Gas
March 2020 - 301C

Jurisdiction	Rate	Transactions	Therms	Revenue without Tax	State Tax	City Tax	Excise Tax	Other Tax
TN	301	174,508	17708962	$ 14,889,469.61	$ 37.07	$ 638,774.12	$ -	$ -
TN	302	17,890	7,138,739	$ 5,778,200.55	$ 351,590.85	$ 299,371.61	$ -	$ -
TN	328	-	0	$ -	$ -	$ -	$ -	$ -
TN	331	54	644588	$ 349,913.33	$ 16,920.49	$ 18,450.43	$ -	$ -
TN	341	2	19015	$ 7,104.82	$ 480.13	$ 419.48	$ -	$ -
TN	352	595	2,609,587	$ 1,959,225.84	$ 91,144.63	$ 103,666.60	$ -	$ -
TN	365	17	7,250	$ 1,404.04	$ 22.33	$ 84.52	$ -	$ -
TN	371	75	1,864,523	$ 487,683.12	$ -	$ 28,559.06	$ -	$ -
TN	372	53	7,975,224	$ 400,713.11	$ -	$ 23,703.17	$ -	$ -
TN	373	1	474,885	$ 20,620.98	$ -	$ -	$ -	$ -
TN	381	3	3,338	$ 3,146.93	$ -	$ 71.78	$ -	$ -
TN TOTAL		**193,198**	**38,446,111**	**$ 23,897,482.33**	**$ 460,195.50**	**$ 1,113,100.77**	**$ -**	**$ -**

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-15. Provide the monthly billing determinants (usage, bills, billing demand, and any other tariff elements) in Excel and PDF format from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 by customer class (Residential, Commercial, Industrial, Public Authority, Interruptible Transportation, Firm Transportation and Special Contract) by Rate Schedule and by Rate Block (usage steps).

RESPONSE: Please see the Company's response to Request No. 13 (620B Reports in Excel and PDF) of this data request for monthly usage and bills by Rate Schedule from May 2011 through March 2020.

Also, please see the four attachments that contain the monthly billing demand determinants and usage by steps for the applicable Rate Schedules from May 2011 through March 2020.

Name and Title of Preparer: Doug Templeton - Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Kally Couzens - Manager Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12
Tariff Rate Schedule 303 - Firm General Sales [1]	5,436	5,452	5,701	5,526	5,526	5,526	5,526	5,526	5,526
Tariff Rate Schedule 313 - Firm Transportation [1]	18,201	18,074	18,609	18,341	18,341	18,341	18,341	18,341	12,845
Tariff Rate Schedule 310 - Resale Service	1,400	200	200	200	200	200	200	200	200
Special Contracts	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
Tariff Rate Schedule 303 - Firm General Sales [1]	5,526	5,526	5,526	5,526	4,321	4,321	4,321	4,321	4,321
Tariff Rate Schedule 313 - Firm Transportation [1]	12,845	12,765	12,765	12,765	11,953	11,953	11,953	11,796	11,796
Tariff Rate Schedule 310 - Resale Service	200	200	200	200	200	200	200	200	200
Special Contracts	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13
Tariff Rate Schedule 303 - Firm General Sales [1]	4,371	4,371	4,371	4,371	4,371	4,371	4,371	4,752	4,752
Tariff Rate Schedule 313 - Firm Transportation [1]	11,906	11,906	11,906	11,906	11,906	11,906	11,906	11,698	11,698
Tariff Rate Schedule 310 - Resale Service	200	200	200	200	200	200	200	200	200
Special Contracts	2,000	2,000	2,000	2,000	2,000	2,000	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14
Tariff Rate Schedule 303 - Firm General Sales [1]	4,752	4,752	4,802	4,802	4,802	4,802	4,802	4,802	4,802
Tariff Rate Schedule 313 - Firm Transportation [1]	11,643	11,643	11,643	11,643	11,643	11,643	11,643	11,604	11,604
Tariff Rate Schedule 310 - Resale Service	200	200	200	200	200	200	200	200	200
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
Tariff Rate Schedule 303 - Firm General Sales [1]	4,802	6,153	6,335	6,153	6,153	6,153	6,153	6,153	6,153
Tariff Rate Schedule 313 - Firm Transportation [1]	11,604	14,124	13,994	13,994	13,994	13,994	13,994	13,994	13,895
Tariff Rate Schedule 310 - Resale Service	200	200	200	200	200	200	50	50	50
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
Tariff Rate Schedule 303 - Firm General Sales [1]	6,153	6,253	6,303	6,203	6,399	6,399	6,399	6,756	6,756
Tariff Rate Schedule 313 - Firm Transportation [1]	13,945	13,945	13,995	14,112	13,809	13,809	13,809	13,809	13,809
Tariff Rate Schedule 310 - Resale Service	50	50	50	50	50	50	50	50	50
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16
Tariff Rate Schedule 303 - Firm General Sales [1]	6,756	6,756	6,756	6,756	6,756	6,756	6,896	6,346	6,364
Tariff Rate Schedule 313 - Firm Transportation [1]	14,001	14,001	14,065	14,065	14,065	14,065	14,128	13,392	13,392
Tariff Rate Schedule 310 - Resale Service	50	50	50	50	50	50	50	50	50
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
Tariff Rate Schedule 303 - Firm General Sales [1]	6,311	6,311	6,210	6,092	6,204	6,204	6,204	6,294	6,294
Tariff Rate Schedule 313 - Firm Transportation [1]	13,392	13,392	13,493	13,493	13,219	13,219	13,036	13,036	13,036
Tariff Rate Schedule 310 - Resale Service	50	50	50	50	50	50	150	150	150
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18
Tariff Rate Schedule 303 - Firm General Sales [1]	6,210	5,774	5,774	5,774	5,774	5,774	5,774	5,653	5,714
Tariff Rate Schedule 313 - Firm Transportation [1]	13,036	13,216	13,216	13,216	13,216	13,152	13,152	13,152	13,152
Tariff Rate Schedule 310 - Resale Service	150	150	150	150	150	150	150	150	150
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
Tariff Rate Schedule 303 - Firm General Sales [1]	7,629	6,555	6,555	6,555	6,759	6,612	6,843	6,993	6,943
Tariff Rate Schedule 313 - Firm Transportation [1]	13,152	13,152	13,152	13,152	14,828	14,682	14,682	14,682	14,732
Tariff Rate Schedule 310 - Resale Service	150	150	150	150	150	150	150	150	150
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19
Tariff Rate Schedule 303 - Firm General Sales [1]	7,079	7,067	7,067	6,975	6,891	6,986	6,986	6,642	6,783
Tariff Rate Schedule 313 - Firm Transportation [1]	14,732	14,732	14,732	14,732	14,732	14,638	14,638	13,126	13,000
Tariff Rate Schedule 310 - Resale Service	150	150	150	150	150	150	150	150	150
Special Contracts	-	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 2 of 4

Billing Demand Determinants
In Dekatherms

Description	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20
Tariff Rate Schedule 303 - Firm General Sales [1]	6,783	6,783	6,833	6,833	6,833	6,543	6,543	6,543
Tariff Rate Schedule 313 - Firm Transportation [1]	13,000	13,000	13,000	13,311	12,937	12,937	12,937	12,937
Tariff Rate Schedule 310 - Resale Service	150	150	150	150	150	150	150	150
Special Contracts	-	-	-	-	-	-	-	-

1/ Includes Tariff Rate Schedule 343 Motor Vehicle Fuel

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 4 of 4

Usage in Dekatherms

Tariff Rate Schedule	Description	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
303	Firm General Sales Service																		
	1st 1,500	20,030	16,428	15,264	15,462	18,500	25,973	35,578	49,697	50,314	48,208	28,544	23,104	18,504	15,670	15,749	16,199	17,082	25,972
	1,501 - 4,000	6,170	4,440	4,174	5,122	7,049	10,112	10,262	19,915	22,662	19,253	11,491	8,944	6,893	3,152	2,435	4,522	4,057	6,740
	4,001 - 9,000	2,988	1,544	1,392	1,637	2,248	1,697	3,750	5,146	6,063	10,181	4,886	3,365	2,134	-	-	240	293	520
	Over 9,000	-	-	-	-	-	-	-	727	306	256	-	-	-	-	-	-	-	-
	Total	**29,188**	**22,412**	**20,829**	**22,221**	**27,798**	**37,781**	**49,590**	**75,485**	**79,345**	**77,898**	**44,920**	**35,413**	**27,531**	**18,822**	**18,185**	**20,960**	**21,432**	**33,231**
332	Small General Service Value																		
	1st 200	158,749	144,769	132,675	123,511	135,482	142,443	160,377	189,984	222,443	205,837	(3)	4	-	42	-	-	-	-
	Over 200	10,539	6,425	5,439	3,806	5,407	6,059	8,680	17,692	30,228	21,876	-	-	-	-	-	-	-	-
	Total	**169,288**	**151,194**	**138,114**	**127,317**	**140,889**	**148,502**	**169,057**	**207,676**	**252,670**	**227,713**	**(3)**	**4**	**-**	**42**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																		
	1st 1,500	446	-	-	-	-	-	1,457	1,500	1,500	1,500	876	1,081	151	-	365	609	275	1,500
	1,501 - 4,000								531.1	962	589.9	-	-	-	-	-	-	-	268
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**446**	**-**	**-**	**-**	**-**	**-**	**1,457**	**2,031**	**2,462**	**2,090**	**876**	**1,081**	**151**	**-**	**365**	**609**	**275**	**1,768**
362	Medium General Service Value																		
	1st 500	42,170	41,313	37,030	33,148	38,679	42,364	49,461	57,213	60,813	60,138	-	-	-	-	-	-	-	-
	Over 500	6,972	5,958	5,494	4,107	5,896	7,560	10,565	18,320	30,419	23,102	-	-	-	-	-	-	-	-
	Total	**49,141**	**47,271**	**42,525**	**37,256**	**44,575**	**49,924**	**60,026**	**75,532**	**91,233**	**83,240**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																		
	1st 1,500	81,954	67,747	63,060	64,641	73,151	88,395	104,634	119,469	118,551	113,756	91,929	83,261	74,867	68,389	66,508	68,831	73,010	91,946
	1,501 - 4,000	35,511	30,432	25,550	29,945	31,187	40,471	48,923	66,381	68,211	58,689	41,089	36,092	33,276	28,724	27,653	28,502	29,891	46,539
	4,001 - 9,000	13,864	10,407	12,547	14,008	14,841	17,007	19,614	24,385	23,876	18,562	8,647	9,680	14,633	8,417	8,988	10,027	9,381	16,961
	Over 9,000	102,274	95,634	94,368	98,241	96,088	114,826	122,116	133,539	-	362	-	-	13,190	1,384	-	-	-	2,259
	Total	**233,602**	**204,220**	**195,525**	**206,835**	**215,267**	**260,699**	**295,286**	**343,774**	**210,639**	**191,369**	**141,665**	**129,032**	**135,966**	**106,914**	**103,148**	**107,360**	**112,282**	**157,705**
314	Interruptible Transportation Service																		
	1st 1,500	70,397	68,878	67,984	68,742	70,643	72,990	74,436	74,576	70,807	71,457	71,155	72,054	71,861	69,520	68,795	69,898	70,953	72,867
	1,501 - 4,000	76,138	66,680	64,779	72,232	72,537	81,208	82,894	90,619	89,900	83,960	78,902	79,185	78,725	76,363	69,719	77,101	74,701	88,070
	4,001 - 9,000	79,372	76,356	72,474	81,636	74,810	81,954	81,479	92,901	101,539	95,101	85,442	79,872	80,042	80,014	79,732	77,387	75,163	91,323
	Over 9,000	211,641	175,443	189,288	221,754	258,360	276,119	365,671	400,115	592,829	540,376	441,594	384,162	293,603	312,590	303,553	296,450	305,500	412,284
	Total	**437,548**	**387,357**	**394,525**	**444,365**	**476,350**	**512,271**	**604,480**	**658,211**	**855,076**	**790,893**	**677,093**	**615,273**	**524,231**	**538,487**	**521,799**	**520,836**	**526,316**	**664,544**
343/303	Motor Vehicle Fuel - Firm General Sales																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
343/313	Motor Vehicle Fuel - Firm Transportation																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 15 Attachment 4 of 4

Usage in Dekatherms

Tariff Rate Schedule	Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14
303	Firm General Sales Service																		
	1st 1,500	45,163	51,174	57,070	54,086	54,424	30,027	20,732	19,702	20,559	21,159	22,052	33,351	55,218	62,892	66,764	64,334	59,190	32,940
	1,501 - 4,000	12,456	15,943	28,505	22,009	23,711	8,080	4,157	4,069	2,905	4,569	4,990	9,239	19,485	30,744	55,600	34,301	23,021	9,587
	4,001 - 9,000	-	434	368	-	167	-	-	-	-	-	470	676	693	1,158	6,056	1,747	2,218	423
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**57,619**	**67,551**	**85,943**	**76,095**	**78,301**	**38,107**	**24,888**	**23,771**	**23,464**	**25,728**	**27,512**	**43,267**	**75,395**	**94,793**	**128,420**	**100,382**	**84,429**	**42,949**
332	Small General Service Value																		
	1st 200	37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**37**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																		
	1st 1,500	1,500	1,500	1,500	1,500	1,500	2,012	1,442	-	-	267	1,609	2,400	2,065	2,386	1,500	1,500	2,433	2,157
	1,501 - 4,000	975	1,234	1,863	1,196	1,275	-	-	-	-	-	500	715	1,098	1,725	2,380	1,661	908	-
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**2,475**	**2,734**	**3,363**	**2,696**	**2,775**	**2,012**	**1,442**	**-**	**-**	**267**	**2,110**	**3,114**	**3,163**	**4,111**	**3,880**	**3,161**	**3,341**	**2,157**
362	Medium General Service Value																		
	1st 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																		
	1st 1,500	114,243	118,010	123,082	119,704	122,573	94,868	81,656	69,784	69,530	70,337	72,114	88,745	115,825	118,905	120,325	119,262	115,110	87,908
	1,501 - 4,000	56,326	57,408	77,465	60,718	68,888	44,979	36,629	28,867	29,023	28,773	30,448	44,522	63,897	82,678	112,907	84,866	69,399	43,352
	4,001 - 9,000	26,612	24,997	32,447	25,012	27,838	17,671	14,970	11,259	10,727	10,348	11,016	18,023	27,832	34,409	48,419	35,298	28,618	14,846
	Over 9,000	1,957	1,007	3,183	1,016	2,219	-	657	958	-	1,439	-	3,125	1,853	5,095	13,605	8,295	7,070	-
	Total	**199,137**	**201,422**	**236,177**	**206,449**	**221,518**	**157,518**	**133,913**	**110,868**	**109,280**	**110,897**	**113,577**	**154,416**	**209,407**	**241,087**	**295,256**	**247,722**	**220,196**	**146,106**
314	Interruptible Transportation Service																		
	1st 1,500	73,247	73,387	68,525	70,034	71,145	71,755	69,116	67,639	68,335	68,751	69,497	70,972	74,811	74,905	70,863	70,493	74,229	71,030
	1,501 - 4,000	92,896	88,587	89,325	83,629	87,976	87,748	81,384	75,339	77,054	81,283	80,912	92,375	95,479	102,721	93,694	93,760	94,831	85,805
	4,001 - 9,000	91,855	94,236	105,289	97,178	101,514	95,867	86,678	76,082	81,021	84,783	82,000	92,810	98,043	108,693	119,618	114,798	111,558	90,132
	Over 9,000	503,026	565,164	659,393	577,276	595,164	452,661	382,076	313,054	323,098	326,927	346,732	409,035	515,296	589,202	587,690	558,019	564,838	366,409
	Total	**761,024**	**821,374**	**922,532**	**828,117**	**855,798**	**708,031**	**619,254**	**532,115**	**549,508**	**561,743**	**579,141**	**665,192**	**783,629**	**875,520**	**871,865**	**837,070**	**845,456**	**613,376**
343/303	Motor Vehicle Fuel - Firm General Sales																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
343/313	Motor Vehicle Fuel - Firm Transportation																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Piedmont Natural Gas Company, Inc.
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Usage in Dekatherms

Tariff Rate Schedule	Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
303	Firm General Sales Service																		
	1st 1,500	26,190	22,324	23,261	22,370	23,751	28,130	53,258	57,636	62,340	61,003	52,293	30,929	26,185	24,532	24,001	23,817	22,707	29,235
	1,501 - 4,000	6,924	5,057	5,551	5,674	5,595	6,522	16,354	24,935	46,221	48,216	16,413	7,746	6,348	5,428	5,242	6,081	5,415	7,390
	4,001 - 9,000	-	-	-	-	-	315	787	592	1,721	1,331	1,426	-	-	221	-	143	-	121
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**33,113**	**27,381**	**28,812**	**28,044**	**29,346**	**34,967**	**70,398**	**83,162**	**110,281**	**110,550**	**70,132**	**38,675**	**32,533**	**30,181**	**29,242**	**30,041**	**28,122**	**36,746**
332	Small General Service Value																		
	1st 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																		
	1st 1,500	543	1,500	1,500	1,500	1,020	2,072	1,905	2,037	1,500	1,500	2,130	1,364	353	513	64	1,501	1,615	2,237
	1,501 - 4,000	-	729	570	348	-	-	1,264	1,396	1,662	2,286	399					284		
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**543**	**2,229**	**2,070**	**1,848**	**1,020**	**2,072**	**3,169**	**3,432**	**3,162**	**3,786**	**2,529**	**1,364**	**353**	**513**	**64**	**1,785**	**1,615**	**2,237**
362	Medium General Service Value																		
	1st 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																		
	1st 1,500	76,095	66,547	66,794	65,347	68,687	81,712	107,115	108,433	109,189	109,027	104,058	81,058	72,211	67,368	66,656	68,387	76,598	83,060
	1,501 - 4,000	35,626	31,583	32,794	31,903	34,708	42,940	66,952	74,826	93,787	95,379	65,425	43,440	36,021	31,902	30,553	34,015	35,519	43,802
	4,001 - 9,000	11,989	10,388	11,267	12,436	10,967	17,081	30,136	32,634	40,364	39,849	26,935	12,767	9,241	10,475	9,972	10,841	9,401	13,415
	Over 9,000	3,517	1,118	872	844	2,186	1,807	2,910	7,449	8,322	8,517	1,258	1,079	-	1,242	646		2,740	455
	Total	**127,226**	**109,635**	**111,727**	**110,529**	**116,549**	**143,541**	**207,112**	**223,343**	**251,662**	**252,771**	**197,676**	**138,343**	**117,473**	**110,987**	**107,827**	**113,242**	**124,258**	**140,731**
314	Interruptible Transportation Service																		
	1st 1,500	70,978	70,301	70,313	69,901	71,200	74,406	76,635	75,062	73,316	72,352	73,282	71,825	71,775	70,820	70,253	70,529	70,687	71,899
	1,501 - 4,000	82,167	77,013	80,165	79,660	84,013	91,200	99,200	97,418	92,509	89,916	93,867	86,596	85,719	86,180	82,632	85,390	85,156	92,900
	4,001 - 9,000	84,345	80,209	81,888	82,143	83,184	96,675	104,939	108,023	112,094	108,087	107,758	96,908	86,313	88,819	94,597	92,327	89,096	98,388
	Over 9,000	326,231	307,908	353,133	365,724	375,469	399,236	581,237	651,563	684,749	638,561	606,226	469,604	409,555	400,990	417,195	441,428	430,463	455,548
	Total	**563,720**	**535,430**	**585,499**	**597,428**	**613,865**	**661,517**	**862,011**	**932,066**	**962,669**	**908,917**	**881,133**	**724,932**	**653,362**	**646,808**	**664,678**	**689,673**	**675,402**	**718,735**
343/303	Motor Vehicle Fuel - Firm General Sales																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	3,000	4,500	1,500	1,500	1,500	1,500	1,500	1,500
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	2,970	6,196	2,500	2,500	2,500	2,500	2,500	2,500
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	4,155	2,992	3,634	4,364	5,000	5,000	5,000	5,000
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	530	1,200	1,884	2,142
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,124**	**13,688**	**7,634**	**8,364**	**9,530**	**10,200**	**10,884**	**11,142**
343/313	Motor Vehicle Fuel - Firm Transportation																		
	1st 1,500	-	-	-	-	-	-	-	-	-	-	1,500	-	815	562	548	476	512	449
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	1,631	(743)	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3,131**	**(743)**	**815**	**562**	**548**	**476**	**512**	**449**

Piedmont Natural Gas Company, Inc.
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Usage in Dekatherms

Tariff Rate Schedule	Description	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
303	Firm General Sales Service																		
	1st 1,500	42,868	49,478	61,691	59,264	41,968	31,539	26,111	21,984	22,186	22,961	24,112	26,976	41,130	62,307	58,510	49,627	50,408	27,695
	1,501 - 4,000	9,446	13,287	42,351	25,887	9,556	5,985	5,457	3,933	3,429	4,893	3,871	4,763	8,083	29,570	21,735	10,012	12,685	5,733
	4,001 - 9,000	-	51	1,636	788	878	-	-	-	-	-	-	-	100	810	723	106	557	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**52,315**	**62,816**	**105,678**	**85,939**	**52,402**	**37,524**	**31,568**	**25,918**	**25,615**	**27,854**	**27,983**	**31,740**	**49,313**	**92,687**	**80,969**	**59,745**	**63,650**	**33,428**
332	Small General Service Value																		
	1st 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																		
	1st 1,500	1,447	1,930	1,500	1,500	1,206	789	2,096	1,331	2	1,285	1,674	2,056	1,560	1,661	1,505	1,357	1,732	2,054
	1,501 - 4,000		42	1,339	439			1,448				464	120		488	340			
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**1,447**	**1,972**	**2,839**	**1,939**	**1,206**	**789**	**3,544**	**1,331**	**2**	**1,285**	**2,139**	**2,176**	**1,560**	**2,149**	**1,846**	**1,357**	**1,732**	**2,054**
362	Medium General Service Value																		
	1st 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																		
	1st 1,500	96,943	104,593	116,587	113,861	98,289	85,740	78,564	70,130	67,895	70,896	71,690	80,091	96,590	111,314	108,251	101,346	100,211	80,590
	1,501 - 4,000	49,527	58,588	99,008	76,296	58,028	43,237	37,257	27,159	25,393	27,586	28,306	35,625	52,906	79,097	74,931	56,687	61,258	33,545
	4,001 - 9,000	20,705	19,123	44,438	31,816	20,028	17,801	13,397	12,699	12,530	13,001	13,068	15,034	16,995	34,291	31,407	20,842	21,158	13,734
	Over 9,000	1,107	-	7,825	2,849	-	1,215	-	267	-	-	-	-	910	3,823	1,257	953	633	-
	Total	**168,282**	**182,304**	**267,859**	**224,822**	**176,345**	**147,993**	**129,219**	**110,254**	**105,818**	**111,483**	**113,064**	**130,751**	**167,401**	**228,525**	**215,846**	**179,827**	**183,260**	**127,870**
314	Interruptible Transportation Service																		
	1st 1,500	74,257	72,893	71,029	67,905	70,260	69,859	69,726	66,838	65,595	67,466	67,991	69,029	69,461	72,325	68,281	68,133	71,434	69,140
	1,501 - 4,000	92,799	93,876	92,475	90,538	92,108	90,036	89,570	83,084	80,993	86,305	88,703	90,909	94,280	93,859	93,058	85,919	95,217	89,326
	4,001 - 9,000	96,255	96,051	112,516	109,019	101,278	96,100	89,610	89,454	82,592	91,522	93,450	96,410	103,927	105,089	109,397	98,216	104,722	90,661
	Over 9,000	509,104	608,555	797,729	674,514	586,895	503,103	492,092	431,238	455,666	463,975	434,617	435,321	518,791	740,074	726,338	577,163	617,540	474,996
	Total	**772,414**	**871,375**	**1,073,749**	**941,975**	**850,539**	**759,097**	**740,998**	**670,613**	**684,846**	**709,268**	**684,760**	**691,670**	**786,459**	**1,011,348**	**997,074**	**829,430**	**888,912**	**724,122**
343/303	Motor Vehicle Fuel - Firm General Sales																		
	1st 1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,502	3,000
	1,501 - 3,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,629
	3,001 - 9,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
	9,001 - 16,500	1,416	2,338	1,492	2,115	3,350	2,689	3,381	4,708	1,842	3,912	2,907	2,617	2,211	1,835	2,078	1,448	3,494	1,904
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**10,416**	**11,338**	**10,492**	**11,115**	**12,350**	**11,689**	**12,381**	**13,708**	**10,842**	**12,912**	**11,907**	**11,617**	**11,211**	**10,835**	**11,078**	**10,448**	**12,496**	**12,533**
343/313	Motor Vehicle Fuel - Firm Transportation																		
	1st 1,500	432	748	470	574	357	448	583	420	620	777	783	759	613	670	794	1,035	1,307	869
	1,501 - 3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**432**	**748**	**470**	**574**	**357**	**448**	**583**	**420**	**620**	**777**	**783**	**759**	**613**	**670**	**794**	**1,035**	**1,307**	**869**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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Usage in Dekatherms

Tariff Rate Schedule	Description	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18
303	Firm General Sales Service																
	1st 1,500	27,428	23,076	22,213	23,197	23,299	32,795	48,687	60,939	64,420	55,457	54,281	45,258	24,371	22,311	22,194	23,854
	1,501 - 4,000	7,680	6,698	5,171	8,184	8,039	8,356	14,675	36,544	49,926	16,876	19,881	13,439	7,294	6,412	6,216	7,379
	4,001 - 9,000	-	-	-	-	157	1,095	1,689	3,844	6,758	881	1,694	1,109		-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**35,108**	**29,773**	**27,384**	**31,381**	**31,495**	**42,246**	**65,052**	**101,327**	**121,104**	**73,214**	**75,857**	**59,806**	**31,666**	**28,723**	**28,409**	**31,232**
332	Small General Service Value																
	1st 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																
	1st 1,500	1,298	1,500	427	941	1,128	2,481	2,934	2,841	1,500	1,500	1,542	1,647	1,597	1,500	524	899
	1,501 - 4,000		2,018	-	-	-	613	1,147	1,289	1,750	160	358		463	2,244		
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**1,298**	**3,518**	**427**	**941**	**1,128**	**3,094**	**4,081**	**4,131**	**3,250**	**1,660**	**1,901**	**1,647**	**2,060**	**3,744**	**524**	**899**
362	Medium General Service Value																
	1st 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																
	1st 1,500	76,843	70,413	67,927	70,326	72,520	84,283	99,569	109,514	111,244	100,494	105,538	99,519	75,411	70,050	69,122	69,952
	1,501 - 4,000	33,218	27,258	24,708	31,627	32,647	49,699	64,935	89,822	101,849	68,676	72,390	58,601	32,821	26,684	24,149	29,789
	4,001 - 9,000	12,906	13,721	12,940	16,037	14,454	17,634	22,742	37,075	55,235	29,546	30,529	23,239	16,618	16,176	14,014	17,299
	Over 9,000	-	-	-	3,491	45	1,109	1,898	4,437	10,421	3,369	3,786	3,354	1,867	2,453	173	3,655
	Total	**122,967**	**111,393**	**105,575**	**121,480**	**119,665**	**152,725**	**189,143**	**240,848**	**278,748**	**202,086**	**212,243**	**184,714**	**126,717**	**115,363**	**107,458**	**120,695**
314	Interruptible Transportation Service																
	1st 1,500	68,223	65,889	66,692	67,512	67,513	69,000	69,825	70,507	68,272	67,415	68,910	68,884	67,897	65,835	65,749	67,294
	1,501 - 4,000	88,258	81,862	82,480	82,874	84,476	89,009	95,469	96,252	95,702	87,534	95,141	96,037	85,078	78,247	80,405	81,714
	4,001 - 9,000	93,981	90,597	80,848	88,598	85,520	98,844	99,784	108,077	116,283	96,990	99,455	105,110	87,485	85,622	86,993	86,753
	Over 9,000	482,989	417,749	412,412	349,691	339,745	391,386	558,216	689,994	789,565	585,840	631,592	582,067	480,526	423,187	441,443	442,556
	Total	**733,450**	**656,096**	**642,432**	**588,675**	**577,254**	**648,239**	**823,294**	**964,830**	**1,069,821**	**837,778**	**895,099**	**852,097**	**720,986**	**652,890**	**674,589**	**678,316**
343/303	Motor Vehicle Fuel - Firm General Sales																
	1st 1,500	3,000	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
	1,501 - 3,000	4,177	1,854	2,061	1,846	1,339	1,516	1,371	1,410	1,567	1,324	1,634	1,489	1,844	1,865	2,083	2,092
	3,001 - 9,000	5,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	2,829	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**15,006**	**3,354**	**3,561**	**3,346**	**2,839**	**3,016**	**2,871**	**2,910**	**3,067**	**2,824**	**3,134**	**2,989**	**3,344**	**3,365**	**3,583**	**3,592**
343/313	Motor Vehicle Fuel - Firm Transportation																
	1st 1,500	742	2,894	2,463	2,414	2,463	2,362	2,189	2,434	2,216	2,137	2,259	2,249	2,365	2,301	2,273	2,424
	1,501 - 3,000	-	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
	3,001 - 9,000	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
	9,001 - 16,500	-	2,902	2,671	3,943	2,771	3,829	2,912	2,336	2,940	2,063	2,721	2,848	4,434	3,703	4,205	4,769
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-		-		
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**742**	**13,295**	**12,634**	**13,857**	**12,734**	**13,691**	**12,601**	**12,270**	**12,656**	**11,701**	**12,480**	**12,597**	**14,300**	**13,503**	**13,978**	**14,693**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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Usage in Dekatherms

Tariff Rate Schedule	Description	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
303	Firm General Sales Service																
	1st 1,500	24,038	36,618	60,425	63,563	66,511	60,224	61,916	38,409	29,721	26,191	26,095	26,917	26,645	38,782	69,362	68,863
	1,501 - 4,000	7,348	15,159	25,267	35,295	43,617	22,995	24,519	11,391	8,945	7,763	7,630	9,153	7,985	12,074	26,283	27,700
	4,001 - 9,000		5,827	1,616	2,892	2,039	1,453	1,793					157		310	1,286	153
	Over 9,000	-	5,598	(5,598)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**31,386**	**63,202**	**81,710**	**101,750**	**112,168**	**84,671**	**88,228**	**49,799**	**38,665**	**33,953**	**33,725**	**36,227**	**34,631**	**51,165**	**96,931**	**96,715**
332	Small General Service Value																
	1st 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
304	Interruptible General Sales																
	1st 1,500	1,691	2,543	3,000	2,106	1,500	1,500	1,738	1,379	909	1,236	955	285	1,507	2,782	2,264	2,187
	1,501 - 4,000	902	1,076	891	621	1,175	184							1,442	360	1,188	1,215
	4,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**2,593**	**3,619**	**3,891**	**2,727**	**2,675**	**1,684**	**1,738**	**1,379**	**909**	**1,236**	**955**	**285**	**2,949**	**3,142**	**3,453**	**3,402**
362	Medium General Service Value																
	1st 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
313	Firm Transportation Service																
	1st 1,500	71,822	91,699	109,134	110,024	111,597	108,950	107,870	86,960	76,464	68,305	66,188	68,019	66,572	82,141	103,301	101,245
	1,501 - 4,000	28,583	49,777	77,697	84,852	95,650	70,975	73,023	47,675	35,896	32,161	31,364	31,348	26,815	45,083	67,358	70,385
	4,001 - 9,000	14,557	17,676	29,166	35,635	45,490	27,304	29,539	17,238	16,412	16,654	13,928	15,654	11,155	19,173	24,106	28,241
	Over 9,000	-	820	3,115	4,387	10,101	6,203	4,295	58	1,399	606	-	1,656	-	2,934	2,874	4,473
	Total	**114,961**	**159,972**	**219,112**	**234,897**	**262,839**	**213,431**	**214,726**	**151,932**	**130,171**	**117,726**	**111,480**	**116,678**	**104,542**	**149,332**	**197,639**	**204,344**
314	Interruptible Transportation Service																
	1st 1,500	67,562	69,031	71,134	72,000	70,500	66,639	70,527	70,408	69,511	66,276	67,432	67,415	67,500	70,952	69,644	68,927
	1,501 - 4,000	82,851	93,451	99,028	98,940	97,543	89,499	100,075	94,974	88,667	82,694	83,991	84,992	82,323	95,281	100,079	97,130
	4,001 - 9,000	81,950	101,287	103,949	104,744	112,081	95,916	112,386	100,120	86,464	78,971	85,762	85,767	78,774	98,158	111,159	108,196
	Over 9,000	406,852	530,131	655,399	688,780	760,116	607,228	659,335	466,441	445,692	420,444	435,795	421,744	402,774	483,213	636,476	644,033
	Total	**639,216**	**793,900**	**929,510**	**964,464**	**1,040,240**	**859,283**	**942,322**	**731,943**	**690,334**	**648,385**	**672,979**	**659,918**	**631,371**	**747,604**	**917,358**	**918,286**
343/303	Motor Vehicle Fuel - Firm General Sales																
	1st 1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
	1,501 - 3,000	1,951	1,930	1,576	1,556	1,606	1,339	1,642	1,598	1,861	1,900	2,322	1,937	1,780	1,895	1,764	1,816
	3,001 - 9,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	9,001 - 16,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16,501 - 30,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**3,451**	**3,430**	**3,076**	**3,056**	**3,106**	**2,839**	**3,142**	**3,098**	**3,361**	**3,400**	**3,822**	**3,437**	**3,280**	**3,395**	**3,264**	**3,316**
343/313	Motor Vehicle Fuel - Firm Transportation																
	1st 1,500	2,189	2,353	2,285	2,275	2,477	2,454	2,365	2,393	2,210	2,181	2,263	2,233	2,346	2,814	2,625	2,287
	1,501 - 3,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
	3,001 - 9,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
	9,001 - 16,500	3,325	4,764	3,885	3,271	5,022	3,185	3,940	4,835	5,105	4,283	5,386	5,533	4,927	4,920	3,443	3,343
	16,501 - 30,000																
	Over 60,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**13,014**	**14,617**	**13,670**	**13,046**	**14,998**	**13,140**	**13,806**	**14,728**	**14,815**	**13,963**	**15,150**	**15,266**	**14,773**	**15,234**	**13,569**	**13,129**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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Usage in Dekatherms

Tariff Rate Schedule	Description	Jan-20	Feb-20	Mar-20
303	Firm General Sales Service			
	1st 1,500	73,771	72,107	51,929
	1,501 - 4,000	32,597	31,508	9,760
	4,001 - 9,000	1,498	1,859	
	Over 9,000	-	-	-
	Total	**107,866**	**105,474**	**61,689**
332	Small General Service Value			
	1st 200	-	-	-
	Over 200	-	-	-
	Total	**-**	**-**	**-**
304	Interruptible General Sales			
	1st 1,500	1,503	1,500	1,502
	1,501 - 4,000	1,369	1,410	399
	4,001 - 9,000	-	-	-
	Over 9,000	-	-	-
	Total	**2,872**	**2,910**	**1,902**
362	Medium General Service Value			
	1st 500	-	-	-
	Over 500	-	-	-
	Total	**-**	**-**	**-**
313	Firm Transportation Service			
	1st 1,500	104,032	103,610	94,253
	1,501 - 4,000	81,680	77,254	56,043
	4,001 - 9,000	30,314	31,811	20,361
	Over 9,000	5,356	5,444	2,162
	Total	**221,382**	**218,119**	**172,819**
314	Interruptible Transportation Service			
	1st 1,500	69,769	69,471	70,697
	1,501 - 4,000	93,490	92,362	97,012
	4,001 - 9,000	113,094	107,154	103,175
	Over 9,000	696,962	659,438	526,638
	Total	**973,315**	**928,425**	**797,522**
343/303	Motor Vehicle Fuel - Firm General Sales			
	1st 1,500	1,500	1,500	1,500
	1,501 - 3,000	1,497	1,238	1,269
	3,001 - 9,000	-	-	-
	9,001 - 16,500	-	-	-
	16,501 - 30,000	-	-	-
	Over 60,000	-	-	-
	Total	**2,997**	**2,738**	**2,769**
343/313	Motor Vehicle Fuel - Firm Transportation			
	1st 1,500	2,315	2,298	1,979
	1,501 - 3,000	2,500	2,500	2,500
	3,001 - 9,000	5,000	5,000	5,000
	9,001 - 16,500	3,966	2,884	4,154
	16,501 - 30,000			
	Over 60,000	-	-	-
	Total	**13,781**	**12,682**	**13,634**

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-16. Provide the monthly billing determinants for Other Revenues (forfeited discounts, reconnections/disconnections, bad check charges, rent from gas property, etc.) in Excel and PDF format from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

RESPONSE: Please see the two attachments.

Name and Title of Preparer: Doug Templeton - Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Kally Couzens - Manager Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 16 Attachment 2 of 2

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$131,750**	**$69,707**	**$47,260**	**$54,137**	**$52,107**	**$61,745**	**$69,294**	**$157,978**	**$215,771**	**$301,470**
Reconnection Revenue	**$14,665**	**$14,028**	**$11,220**	**$11,250**	**$22,820**	**$55,365**	**$45,025**	**$23,885**	**$21,919**	**$26,015**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$55	$55	$55	$55	$85	$85	$85	$85	$85	$55
Non-Sufficient Funds Revenue	**$3,560**	**$3,920**	**$2,975**	**$3,179**	**$2,684**	**$2,947**	**$2,660**	**$3,365**	**$2,580**	**$3,620**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$452**	**$629**	**-$444**	**$340**	**$149**	**$191**	**$294**	**$119**	**$297**	**$313**
Rent from Gas Properties	**$0**	**$0**	**$0**	**$0**	**$2,117**	**$2,117**	**$2,117**	**$2,117**	**$2,117**	**$2,117**
Cost of Gas Cash-outs / Secondary Marketing	**$49,082**	**$21,951**	**$263,388**	**$16,506**	**$29,249**	**$82,198**	**$352,484**	**$1,059,712**	**$343,010**	**$87,293**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 16 Attachment 2 of 2

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$223,512**	**$177,566**	**$106,753**	**$59,612**	**$61,548**	**$54,118**	**$58,143**	**$72,143**	**$99,291**	**$192,377**
Reconnection Revenue	**$26,450**	**$14,355**	**$14,725**	**$8,470**	**$3,630**	**$8,170**	**$15,055**	**$59,430**	**$42,090**	**$16,260**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$55	$55	$55	$55	$55	$55	$85	$85	$85	$85
Non-Sufficient Funds Revenue	**$2,960**	**$2,790**	**$2,240**	**$1,400**	**$1,620**	**$1,020**	**$1,400**	**$1,705**	**$1,345**	**$1,660**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$400**	**$446**	**$406**	**$135**	**$285**	**$220**	**$328**	**$285**	**$257**	**$161**
Rent from Gas Properties	**$2,117**	**$2,180**	**$2,180**	**$2,180**	**$2,180**	**$2,180**	**$2,180**	**$2,180**	**$2,180**	**$2,180**
Cost of Gas Cash-outs / Secondary Marketing	**$712**	**$8,396**	**$55,126**	**$477**	**$131,678**	**$52,426**	**$164,599**	**$46,230**	**$36,446**	**$46,850**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$196,760**	**$274,184**	**$307,830**	**$225,220**	**$145,219**	**$99,101**	**$70,676**	**$50,935**	**$66,974**	**$67,569**
Reconnection Revenue	**$10,174**	**$10,346**	**$6,130**	**$11,165**	**$8,825**	**$7,425**	**$6,503**	**$6,220**	**$6,565**	**$48,695**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$85	$55	$55	$55	$55	$55	$55	$55	$85	$85
Non-Sufficient Funds Revenue	**$2,120**	**$2,220**	**$1,859**	**$1,860**	**$1,780**	**$1,440**	**$1,685**	**$1,160**	**$680**	**$1,535**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$298**	**$345**	**$478**	**$408**	**$424**	**$822**	**$392**	**$499**	**$471**	**$596**
Rent from Gas Properties	**$2,180**	**$2,180**	**$2,180**	**$2,246**	**$2,246**	**$2,246**	**$2,246**	**$2,246**	**$2,246**	**$2,246**
Cost of Gas Cash-outs / Secondary Marketing	**$13,163**	**$40,994**	**$701,186**	**$2,996,496**	**$337,235**	**$992,405**	**$84,851**	**$1,364,912**	**$1,064,827**	**$1,617,800**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$75,432**	**$179,132**	**$273,499**	**$467,388**	**$483,908**	**$328,244**	**$176,926**	**$114,065**	**$74,544**	**$79,395**
Reconnection Revenue	**$31,590**	**$12,640**	**$8,525**	**$5,805**	**$12,210**	**$15,125**	**$13,750**	**$11,220**	**$7,272**	**$9,160**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$85	$85	$85	$55	$55	$55	$55	$55	$55	$55
Non-Sufficient Funds Revenue	**$1,525**	**$1,760**	**$1,945**	**$1,515**	**$2,180**	**$2,340**	**$2,180**	**$1,340**	**$1,120**	**$1,280**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$544**	**$1,174**	**$1,519**	**$988**	**$684**	**-$828**	**$884**	**-$525**	**$855**	**$694**
Rent from Gas Properties	**$2,246**	**$2,246**	**$2,246**	**$2,246**	**$2,246**	**$2,313**	**$2,313**	**$2,313**	**$2,313**	**$2,313**
Cost of Gas Cash-outs / Secondary Marketing	**$109,717**	**$783,946**	**$87,990**	**$568,564**	**$6,614**	**$732,212**	**$63,741**	**$61,621**	**$24,125**	**$7,795**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$88,735**	**$73,208**	**$89,983**	**$292,361**	**$326,462**	**$521,732**	**$520,639**	**$289,434**	**$135,806**	**$91,912**
Reconnection Revenue	**$24,935**	**$57,111**	**$53,394**	**$20,146**	**$9,330**	**$3,600**	**$19,660**	**$22,275**	**$22,495**	**$6,961**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$85	$85	$85	$85	$85	$55	$55	$55	$55	$55
Non-Sufficient Funds Revenue	**$720**	**$1,040**	**$1,140**	**$1,400**	**$2,000**	**$1,320**	**$1,480**	**$2,140**	**$1,600**	**$1,260**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$951**	**$1,027**	**$1,231**	**$1,079**	**$918**	**$1,514**	**$1,554**	**$1,785**	**$1,563**	**$1,352**
Rent from Gas Properties	**$2,313**	**$2,313**	**$2,313**	**$2,313**	**$2,313**	**$2,313**	**$2,313**	**$2,383**	**$0**	**$2,383**
Cost of Gas Cash-outs / Secondary Marketing	**$27,762**	**$59,162**	**$198,712**	**$1,470,818**	**-$7,645**	**$41,031**	**$15,709**	**$63,488**	**$241,445**	**$20,687**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$78,133**	**$66,184**	**$69,828**	**$76,323**	**$93,027**	**$142,483**	**$216,020**	**$364,951**	**$402,322**	**$209,086**
Reconnection Revenue	**$8,034**	**$9,825**	**$18,129**	**$53,941**	**$53,582**	**$21,426**	**$13,080**	**$6,909**	**$20,025**	**$20,570**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$55	$55	$85	$85	$85	$85	$85	$55	$55	$55
Non-Sufficient Funds Revenue	**$1,340**	**$1,445**	**$1,200**	**$920**	**$1,080**	**$1,325**	**$1,505**	**$1,880**	**$1,600**	**$1,665**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**-$11**	**$2,588**	**$1,622**	**$891**	**$741**	**$1,566**	**$2,916**	**$71**	**$3,287**	**$864**
Rent from Gas Properties	**$2,383**	**$2,383**	**$2,383**	**$0**	**$4,765**	**$2,383**	**$2,383**	**$2,383**	**$2,383**	**$0**
Cost of Gas Cash-outs / Secondary Marketing	**$18,322**	**$27,316**	**$49,729**	**$12,941**	**$93,818**	**$242,589**	**-$3,472**	**$63,999**	**$77,831**	**$114,820**
CNG Volume Rebate	**$0**	**-$78**	**$0**	**$0**	**-$13**	**$0**	**$0**	**$0**	**-$1,542**	**$0**

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	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$125,227**	**$82,049**	**$62,867**	**$55,230**	**$57,095**	**$60,974**	**$78,354**	**$140,640**	**$225,936**	**$350,260**
Reconnection Revenue	**$18,450**	**$11,250**	**$9,593**	**$11,910**	**$12,727**	**$33,521**	**$67,546**	**$26,170**	**$11,751**	**$11,000**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$55	$55	$55	$55	$85	$85	$85	$85	$85	$55
Non-Sufficient Funds Revenue	**$1,360**	**$1,300**	**$1,179**	**$1,100**	**$1,220**	**$885**	**$1,240**	**$1,360**	**$1,920**	**$1,760**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$2,235**	**-$11**	**-$1,291**	**$1,561**	**$2,101**	**$2,266**	**$1,917**	**$1,802**	**-$566**	**$2,014**
Rent from Gas Properties	**$5,036**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$0**
Cost of Gas Cash-outs / Secondary Marketing	**$18,340**	**$24,287**	**$37,424**	**$19,218**	**$34,965**	**$20,576**	**$13,551**	**$30,277**	**$60,957**	**$2,824**
CNG Volume Rebate	**$0**	**$0**	**$0**	**-$1,787**	**-$1,591**	**$0**	**$0**	**-$1,801**	**$0**	**-$2,208**

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	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$303,400**	**$275,935**	**$186,477**	**$107,284**	**$86,181**	**$105,695**	**$67,000**	**$103,249**	**$108,381**	**$152,032**
Reconnection Revenue	**$19,555**	**$11,220**	**$10,120**	**$13,970**	**$8,525**	**$11,175**	**$16,865**	**$53,940**	**$56,268**	**$21,171**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$55	$55	$55	$55	$55	$55	$85	$85	$85	$85
Non-Sufficient Funds Revenue	**$2,300**	**$1,300**	**$1,865**	**$1,680**	**$920**	**$1,300**	**$832**	**$1,360**	**$1,200**	**$1,240**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$2,190**	**$2,114**	**$2,364**	**$1,121**	**$816**	**$1,095**	**$1,657**	**$1,971**	**$2,164**	**$2,336**
Rent from Gas Properties	**$2,654**	**$5,307**	**$2,654**	**$2,654**	**$2,654**	**$2,654**	**$0**	**$2,654**	**$7,961**	**$2,654**
Cost of Gas Cash-outs / Secondary Marketing	**$293,755**	**$42,749**	**$7,031**	**$7,846**	**$30,264**	**$48,904**	**$527**	**$118,594**	**$86,775**	**$34,626**
CNG Volume Rebate	**$0**	**$0**	**-$5,044**	**$0**	**$0**	**$0**	**-$5,221**	**$0**	**$0**	**-$2,006**

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	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$283,021**	**$468,959**	**$417,483**	**$221,716**	**$231,685**	**$87,336**	**$70,480**	**$63,354**	**$63,154**	**$92,248**
Reconnection Revenue	**$12,410**	**$9,845**	**$12,705**	**$11,535**	**$11,385**	**$12,760**	**$9,680**	**$16,325**	**$13,545**	**$71,425**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$85	$55	$55	$55	$55	$55	$55	$55	$85	$85
Non-Sufficient Funds Revenue	**$1,900**	**$1,700**	**$2,565**	**$1,980**	**$1,600**	**$1,180**	**$1,000**	**$1,125**	**$1,125**	**$1,220**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$2,552**	**$2,302**	**$2,223**	**$1,842**	**$1,702**	**$1,713**	**-$2,368**	**$1,627**	**$1,546**	**$1,007**
Rent from Gas Properties	**$0**	**$2,654**	**$0**	**$0**	**$0**	**$0**	**$0**	**$7,961**	**$0**	**$0**
Cost of Gas Cash-outs / Secondary Marketing	**$169,683**	**$14,103**	**$16,097**	**$60,457**	**$4,802**	**$136,489**	**$7,072**	**$2,618**	**$98,492**	**$43,268**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**$0**	**-$1,624**	**$0**	**$0**	**$0**	**-$1,618**

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	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$104,572**	**$261,537**	**$412,188**	**$345,470**	**$346,110**	**$229,802**	**$128,354**	**$68,069**	**$57,460**	**$61,534**
Reconnection Revenue	**$46,724**	**$11,845**	**$11,645**	**$14,215**	**$14,481**	**$20,760**	**$16,665**	**$14,105**	**$10,615**	**$8,450**
($55 Reconnect charge per occurance Feb thru Aug) *($85 Reconnect charge per occurance Sep thru Jan)*	$85	$85	$85	$55	$55	$55	$55	$55	$55	$55
Non-Sufficient Funds Revenue	**$1,145**	**$1,480**	**$2,220**	**$2,340**	**$2,600**	**$2,580**	**$2,118**	**$1,540**	**$1,460**	**$1,439**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$1,022**	**$1,045**	**$1,056**	**$1,065**	**$917**	**$936**	**$953**	**-$9,553**	**$815**	**$827**
Rent from Gas Properties	**$0**	**$9,816**	**$0**	**$0**	**$0**	**$0**	**$0**	**$22,086**	**$0**	**$0**
Cost of Gas Cash-outs / Secondary Marketing	**$42,193**	**$5,101**	**$19,356**	**$32,700**	**$3,614**	**$1,611**	**$107,638**	**$5,091**	**$5,235**	**$4,975**
CNG Volume Rebate	**$0**	**$0**	**$0**	**$0**	**-$1,246**	**$0**	**-$2,320**	**$0**	**$0**	**$0**

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	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-19 to Mar-20 Test Period
Forfeited Discounts / Gas Late Payment Revenue *(5% Gross billing charge)*	**$55,912**	**$56,389**	**$68,670**	**$161,036**	**$211,703**	**$247,454**	**$126,352**	**$1,472,734**
Reconnection Revenue	**$11,979**	**$62,796**	**$41,985**	**$9,660**	**$15,425**	**$15,240**	**$4,353**	**$232,032**
($55 Reconnect charge per occurance Feb thru Aug)								
($85 Reconnect charge per occurance Sep thru Jan)	$85	$85	$85	$85	$85	$55	$55	
Non-Sufficient Funds Revenue	**$854**	**$1,065**	**$940**	**$1,345**	**$2,040**	**$1,980**	**$820**	**$18,181**
($20 Returned check charge)	$20	$20	$20	$20	$20	$20	$20	
Late Payment on Misc. Revenue & Other *(1.5% Late payment charge on non-utility balances)*	**$840**	**$850**	**$862**	**$877**	**$886**	**$900**	**$914**	**$107**
Rent from Gas Properties	**$0**	**$0**	**$0**	**$15,921**	**$0**	**$5,307**	**$0**	**$43,314**
Cost of Gas Cash-outs / Secondary Marketing	**$144,996**	**$41,913**	**$4,485**	**$26,575**	**$17,473**	**$18,333**	**$1,404**	**$379,728**
CNG Volume Rebate	**$0**	**-$626**	**$0**	**$0**	**$0**	**-$1,880**	**$0**	**-$4,826**

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-17. For each of the Company's tariffs, provide a schedule showing the number of customers, total sales, total margin at current rates, total margin at proposed rates and the percentage increase in margin in incremental 1% usage blocks for the test period.

RESPONSE: See the attachment.

Name and Title of Preparer: Paul Mosley, Rates & Regulatory Strategy Analyst; Kally Couzens, Manager - Rates & Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates & Regulatory Strategy

Responses provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-18. Refer to the Company's response to MFR #17 regarding the historical usage for the Company's 25 largest customers. Provide the monthly usage by step rate for January 2020 through March 2020 for each of these customers.

RESPONSE: See CONFIDENTIAL attachment.

Name and Title of Preparer: Sharon Middleton, Supervisor Sales

Name and Title of Responsible Person: Ron Mays, VP - Gas Sales & Delivery

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-19. Refer to the Company's response to MFR #17 regarding the historical usage for the Company's 25 largest customers. Provide the monthly billing demand for these customers with firm accounts from January 2017 through March 2020.

RESPONSE: See CONFIDENTIAL attachment.

Name and Title of Preparer: Sharon Middleton, Supervisor – Sales

Name and Title of Responsible Person: Ron Mays, VP - Gas Sales & Delivery

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-20. Refer to the Company's response to MFR #17 regarding the historical usage for the Company's 25 largest customers. For each customer identified in this response, provide the following information:

a. The contact name and phone number of the individual at each company that is most familiar with their gas consumption.

b. All correspondence with the customers from May 2011 (the end of the last rate case in Docket 11-00144) through the most recent date regarding historical, projected or anticipated changes to their gas consumption.

c. The monthly sales or transportation volumes at each meter point for each customer from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

d. A copy of each customer's monthly bill from April 2019 through March 2020.

RESPONSE: Please see the 27 CONFIDENTIAL attachments.

Name and Title of Preparer: Sharon Middleton, Supervisor Sales

Name and Title of Responsible Person: Ron Mays, VP - Gas Sales & Delivery

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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Date Issued: August 17, 2020
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1-21. Refer to Page 5, Lines 11 – 12 of the direct testimony of Company witness Couzens where she states that Piedmont "...also reviewed the Test Period usage for each Large General Service Customer." Provide a copy of the Company workpapers and correspondence related to this review.

RESPONSE: The thirty-year average heating degree days of 15.90 for February 29th (leap day) was computed by taking an average of the eight leap days that occurred from 1991 to 2020. The heating degree days for February 29th should have been adjusted to reflect that leap year occurs once every four years.

Name and Title of Preparer: Kally Couzens, Manager - Rates & Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

Couzens, Kally

From: Nestor, David
Sent: Wednesday, May 20, 2020 8:07 AM
To: Couzens, Kally
Cc: Benson, Jessica A.; Gifford, Chip
Subject: RE: TN Rate Case - CNG Customers
Attachments: TN CNG Proforma Information-20May2020.xlsx

We updated the ProForma spreadsheet with the requested information. See attached. Below are our responses to the questions you asked.

1) Do we expect the current 4 tariff CNG customers to have the same usage in the attrition period as the test period? Please provide a brief explanation if yes. If no, please provide the recommended adjustments and a brief explanation. *You can use the attached template to provide adjustment data.*
For (2) of the tariff CNG customers we expect them to have the same usage based on their historical usage, number of CNG trucks they have at their site, and the site limitations for adding more CNG trucks. For the other (2) tariff CNG customers we have included them on the attached spreadsheet along with an explanation on their anticipated change in usage.

2) Do we expect to add more tariff TN CNG customers between now and December 2021? If so, please provide the projected attrition period # of bills, usage Dts, demand Dts, etc. in the attached template.
Piedmont anticipates adding (1) additional tariff CNG customer. The requested information is provided on the attached spreadsheet under new customer.

3) It does not appear from our actuals that we apply the $0.50/therm compression charge to any of the existing 4 TN CNG customers. Please confirm that the compression facilities are customer owned.
If Piedmont owns the station, in North Carolina we are allowed to charge up to a $0.40/therm compression charge and in South Carolina we are allowed to charge up to a $0.50/therm compression charge. Piedmont does not have any stations and/or customers where Piedmont charges a compression fee in TN. The compression facilities for the existing (4) tariff TN CNG customers and the (1) new CNG customer are customer owned.

Let us know if you have any questions or need any additional information.

David

From: Couzens, Kally <Kally.Couzens@duke-energy.com>
Sent: Saturday, May 16, 2020 4:40 PM
To: Nestor, David <David.Nestor@duke-energy.com>
Cc: Benson, Jessica A. <Jessica.Benson@duke-energy.com>; Gifford, Chip <Chip.Gifford@duke-energy.com>
Subject: TN Rate Case - CNG Customers

Hi David,
The other day we spoke briefly about the Company's TN rate case and the work that I am doing on the sales and transportation revenue projections. Our test period for the rate case is April 2019 thru March 2020. In this test period, I am reflecting the billing determinates (actual bills and usage Dts) from 4 tariff TN CNG customers. Note, I am only concerned with regulated tariff CNG customers, not the public stations.

My question to your team is if we are projecting revenues for a forward looking attrition period that is January 2021 through December 2021, what adjustments are appropriate for these tariff CNG customers? Please keep in mind that any adjustments or lack of adjustments are subject to discovery by the intervenors in the rate case.

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Remember that we are looking for reasonable and probable adjustments that we are comfortable explaining to the regulators or other rate case intervenors. Also, if you think I am missing anything, please let me know!

Please feel free to contact me with any questions. I am looking to have this information by the May 22nd if possible. Just let me know if that date is not feasible.

Thank you!!

Kally Couzens
Regulatory Affairs
Piedmont Natural Gas Company, Inc.
4720 Piedmont Row Drive
Charlotte, North Carolina 28210
Office: 704-731-4619
Cell: 803-448-4825
kally.couzens@duke-energy.com

DUKE
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Piedmont
Natural Gas

Couzens, Kally

From: Middleton, Sharon B
Sent: Friday, June 5, 2020 10:22 AM
To: Couzens, Kally
Subject: Adjustment to ProForma-2021.xlsx
Attachments: Adjustment to ProForma-2021.xlsx

Couzens, Kally

From: Nestor, David
Sent: Wednesday, May 20, 2020 8:07 AM
To: Couzens, Kally
Cc: Benson, Jessica A.; Gifford, Chip
Subject: RE: TN Rate Case - CNG Customers
Attachments: TN CNG Proforma Information-20May2020.xlsx

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Cc: Benson, Jessica A. <Jessica.Benson@duke-energy.com>; Gifford, Chip <Chip.Gifford@duke-energy.com>
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Kally Couzens
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Charlotte, North Carolina 28210
Office: 704-731-4619
Cell: 803-448-4825
kally.couzens@duke-energy.com

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Natural Gas

Couzens, Kally

From: Middleton, Sharon B
Sent: Friday, June 5, 2020 10:22 AM
To: Couzens, Kally
Subject: Adjustment to ProForma-2021.xlsx
Attachments: Adjustment to ProForma-2021.xlsx

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-21. Refer to Page 5, Lines 11 – 12 of the direct testimony of Company witness Couzens where she states that Piedmont "...also reviewed the Test Period usage for each Large General Service Customer." Provide a copy of the Company workpapers and correspondence related to this review.

RESPONSE:

See the attachments herein, including 3 that are CONFIDENTIAL.

Name and Title of Preparer: Kally Couzens, Manager - Rates & Regulatory Strategy; Sharon Middleton, Supervisor - Sales

Name and Title of Responsible Person: Kally Couzens, Manager - Rates & Regulatory Strategy; Ron Mays, VP – Gas Sales & Delivery; David Nestor, Director - CNG

Revised Response provided by Piedmont Natural Gas Company, Inc. on September 18, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-22. Refer to the Company's response to MFR #27 regarding the historical usage for the Company's special contract customer. Provide the following information relating to this Special Contract customer:

a. Provide the monthly billing determinants for this customer from May 2011 (the end of the last rate case in Docket 11-00144) through March 2019.

b. Provide a copy of the monthly bills for this customer from April 2019 through March 2020.

c. Identify and provide a copy of the Commission Order establishing the Special Contract rate for this customer.

RESPONSE: Please see the 3 attachments, 2 of which are CONFIDENTIAL.

Name and Title of Preparer: Sharon Middleton, Supervisor Sales

Name and Title of Responsible Person: Ron Mays, VP - Gas Sales & Delivery

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD DR 1 Item 22c

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

October 28, 2010

IN RE:	)	
	)	
APPLICATION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR APPROVAL OF NEGOTIATED GAS REDELIVERY AGREEMENT WITH BRIDGESTONE/FIRESTONE	)	**DOCKET NO. 10-00015**

ORDER GRANTING APPROVAL OF SPECIAL CONTRACT

This matter came before Director Eddie Roberson, Director Kenneth C. Hill and Director Sara Kyle of the Tennessee Regulatory Authority ("TRA" or the "Authority"), the voting panel assigned to this Docket, at a regularly scheduled Authority Conference held on September 27, 2010 for consideration of the *Petition* filed on February 2, 2010 by Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company").

BACKGROUND

The *Petition* seeks approval of a Negotiated Gas Redelivery Agreement ("Agreement") with Bridgestone/Firestone ("Bridgestone"). The Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") filed a *Petition to Intervene* on February 24, 2010. On March 30, 2010, an Order was issued convening a contested case and appointing a hearing officer. At a status conference held on August 12, 2010, the Hearing Officer granted the Consumer Advocate's intervention, identified the issues and set up a procedural schedule to set a date for Piedmont to clarify and correct the *Petition* and a date for the Consumer Advocate to respond. Piedmont submitted its *Clarification and Correction of Petition* on August 20, 2010, correcting the incorrect citation in the *Petition* of an order which

allowed the Company to recover one hundred percent margin loss rather than ninety percent. On August 26, 2010, the Consumer Advocate filed its *Statement of the Consumer Advocate's Intent Not to Contest the Negotiated Gas Redelivery Agreement.*

TERMS AND CONDITIONS OF NEGOTIATED GAS REDELIVERY AGREEMENT

The predecessor agreement between the Company and Bridgestone was approved by orders of the Authority issued on January 22, 1999 and April 4, 2003 in Docket Nos. 98-00339[1] and 02-01271,[2] respectively. The initial term of the contract expired on December 31, 2005, providing for automatic one-year renewals, with the requirement that these extensions be submitted for approval by the Authority. The Company failed to submit these renewals.[3] After discovery of the failure to file extensions, the Company and Bridgestone determined to renegotiate the rates of the special contract to avoid bypass of Piedmont's system and subsequently negotiated a new contract, effective October 27, 2009. According to Piedmont, the Agreement was not submitted to the Authority until four months later due to a delay in the executed agreement being sent back to the Company's corporate headquarters, focus on other dockets before the Authority and time required to research and draft a final petition for submission to the Authority.[4] Piedmont has been charging Bridgestone the new contract rates since November 2009 on a conditional basis, subject to Authority approval of the contract.[5]

Pursuant to the contract terms, Piedmont proposes to provide daily firm redelivery service up 250 Dths per day and interruptible redelivery service up to an additional 5,750 Dths

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[1] *See In re: Application of Nashville Gas Company, A Division of Piedmont Natural Gas Company, for Approval of Negotiated Gas Redelivery Agreement with Bridgestone/Firestone*, Docket No. 98-00339.
[2] *See In re: Petition of Nashville Gas Company for Extension of Negotiated Gas Redelivery Agreement with Bridgestone/Firestone Industries*, Docket No. 02-01271.
[3] Piedmont states that their failure to submit the extensions was inadvertent and that they continued to serve Bridgestone under the previously approved rates. *Petition*, p. 3 (February 2, 2010).
[4] *Data Response* (February 23, 2010).
[5] *Id.*

per day.[6] Piedmont states that the new rates will provide margin to the Company equivalent to that provided under the current tariffs[7] but with more service flexibility than that allowed under the tariffs.

The initial term of this proposed Agreement is for five (5) years, with automatic one-year extensions ("Rollover Term(s)") unless one or both parties gives written notice of intent not to renew at least twelve (12) months prior to a new contract becoming effective.[8] The Company requests "in the event Piedmont's tariffed margin allocations are changed in a general rate case proceeding during the effective term of the Agreement, and such changed allocations create a margin loss under the Bridgestone Agreement, Piedmont reserves its right to request recovery of ninety percent of such margin loss consistent with the Authority precedent established in Docket Nos. 98-00339 and 02-01271."[9]

FINDINGS AND CONCLUSIONS

TRA Rule 1220-4-1-.07, states:

> Special contracts between public utilities and certain customers prescribing and providing rates, services and practices not covered by or permitted in the general tariffs, schedules, or rules filed by such utilities are subject to supervision, regulation, and control by the Authority. A copy of such special agreements shall be filed, subject to review and approval.

Following precedents set in prior dockets,[10] the panel noted that the Authority has established and considers four criteria. The criteria are whether:

1. Customer by-pass is imminent;

2. Such by-pass would be uneconomic;

---

[6] *Petition*, p. 4 (February 2, 2010).
[7] Rate Schedule No. 313 and Rate Schedule No. 314.
[8] Gas Redelivery Agreement, Article VII, Exhibit A to *Petition*.
[9] *Clarification and Correction of Petition*, p. 2 (August 20, 2010).
[10] *See e.g. In re: Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, for Approval of Negotiated Gas Redelivery Agreement with Visteon Corporation*, Docket No. 01-00530; *In re: Petition of Nashville Gas Company for Extension of Negotiated Gas Redelivery Agreement with State Industries*, Docket No. 02-01270; *In re: Petition of Nashville Gas Company for Extension of Negotiated Gas Redelivery Agreement with Bridgetsone/Firestone Industries, Docket No. 02-01271.*

3. The contract rates and terms are just and reasonable and are not unjustly preferential or unduly discriminatory; and

4. The contract rates are the highest that could be negotiated.

The panel found that the proposed contract meets the criteria for approval of a discounted long-term transportation contract. The panel also noted that Piedmont reserved the right to recover ninety percent of its margin loss related to negotiated rates as previously allowed by the TRA. The panel found that the Company should be allowed to request ninety percent of its margin loss resulting from the special contract rates consistent with the previous dockets. The panel also found that the agreement is both pro-consumer and pro-business.

Thereafter, the panel voted unanimously to approve the agreement for a five-year term, with an October 27, 2009 effective date and successive one-year terms. Piedmont shall be required to resubmit each year automatic extension following the initial five-year term to ensure that Bridgestone continues to meet the requirements for a long-term special contract and is reminded to submit the renewals in a timely manner.

IT IS THEREFORE ORDERED THAT:

The Negotiated Gas Redelivery Agreement by and between Piedmont Natural Gas Company, Inc. and Bridgestone/Firestone is approved.

Eddie Roberson, Director

Kenneth C. Hill, Director

Sara Kyle, Director

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-23. Refer to the "Minimum Margin Agreements" tab of the "1_Sales and Transportation Pro Forma Revenue -CONFIDENTIAL" spreadsheet included with the Company's filing. Provide the following information relating to Minimum Margin Agreements:

a. Provide a copy of the customer contracts establishing the monthly amount of Minimum Margin Agreement.

b. Cite and provide a copy of the Commission Order permitting the Company's establishment of a Minimum Margin Agreement with its customers.

c. Cite and provide a copy of the Company's tariff permitting the Company's establishment of a Minimum Margin Agreement with its customers.

RESPONSE:

a. See CONFIDENTIAL attachment.

b. Piedmont is not aware of, or in possession of, any Commission order that is responsive to this request.

c. The Company's Service Schedules and Service Regulations limit the Company's obligation to provide service to a new customer by requiring the Company to determine that service will be economically feasible (See Process for Obtaining Consent to New or Changed Service). Evaluating economic feasibility requires certain assumptions about projected customer usage. In cases where the costs of the facilities necessary to serve a new customer would render service economically infeasible, the Company has the choice of declining service, accepting a contribution in aid of construction in the amount of the negative net present value revealed by the feasibility analysis, or attempting to negotiate a special contract

with the customer (which would ultimately require TPUC approval if agreed to by the parties). Minimum margin agreements are intended to address situations where economic feasibility is marginal. The service provided to a customer signing such an agreement is based entirely upon the Company's tariffs (including billing rates) and is indistinguishable from service provided to other customers served under the same Service Schedule. Customers asked to execute a minimum margin agreement essentially provide a guarantee to the Company that if it does not use the amount of gas its feasibility analysis is based upon, which is provided by the customer, it will keep Piedmont whole with respect to the margin loss incurred as a result of its under-usage. Piedmont utilizes such agreements in all three states in which it operates (NC, SC and TN), and because the agreements constitute an economic guaranty rather than establishing the terms or rates for utility service, Piedmont does not file them for Commission approval in any state in which it operates. The agreements ultimately preserve the assumptions upon which service is extended, allow the extension of service to customers who might otherwise be denied gas service, and protect other customers from subsidizing service to a customer where that service might ultimately be determined to be infeasible.

Name and Title of Preparer: Nisha Prasad, Power Generation & Municipal Account Manager

Name and Title of Responsible Person: Ron Mays, VP - Gas Sales & Delivery

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-24. Refer to the "IMR Investment" tab of the "SW_Revenues _IMR Rev Req for Attrition Pd" spreadsheet included with the Company's filing and provide the following information.

a. Provide a copy of the actual monthly IMR filings from November 2019 – March 2020 referenced in this spreadsheet.

b. Provide a copy of the actual monthly IMR filings subsequent to the Company's March 31, 2020 test period.

c. Provide the source and support for the projected monthly IMR filings from April 2020 – October 2020 referenced in this spreadsheet.

RESPONSE:

a. See the six attachments, which contain the filed monthly IMR reports and the supporting Excel files.

b. See the four attachments, which contain the filed monthly IMR reports and the supporting Excel files.

c. The projected monthly IMR data in the "IMR Investment" tab was exported from PowerPlan, Piedmont's asset accounting system.

Name and Title of Preparer: Kally Couzens, Manager - Rates and Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

waller

Waller Lansden Dortch & Davis, LLP
511 Union Street, Suite 2700
P.O. Box 198966
Nashville, TN 37219-8966

615.244.6380 main
615.244.6804 fax
wallerlaw.com

Paul S. Davidson
615.850.8942 direct
paul.davidson@wallerlaw.com

January 14, 2020

VIA HAND DELIVERY
Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: **Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No. 13-00118**

Dear Mr. Taylor:

Enclosed please find an original and five (5) copies of Piedmont Natural Gas Company Inc.'s ("Piedmont" or "Company") Integrity Management Rider ("IMR" or "Rider") Monthly Report for the month ending November 30, 2019.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended November 30, 2019.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original and four copies and stamp the additional copies as "filed." Then please return the stamped copy to me by way of our courier.

Thank you for your assistance with this matter. If you have any questions regarding this filing, you may reach me at the number shown above.

Very truly yours,

Paul S. Davidson

Enclosures

cc: Pia Powers
Bruce Barkley
Michelle Mairs
Emily Knight

RECEIVED
JAN 14 2020
TN PUBLIC UTILITY COMMISSION
DOCKET OFFICE

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8 November 2019 Capital Expenditure [1]	Current Vintage Year: Vintage Year 8 Prior Cumulative Capital Expenditure [2]	Current Vintage Year: Vintage Year 8 Cumulative Capital Expenditure as of November 2019 [3]	All Vintage Years Cumulative Capital Expenditure as of November 2019 [6]
	TN Direct				
1	Corrosion Control	$ 151,896.10	$ -	$ 151,896.10	$ 8,093,619.53
2	Casing Remediation	$ -	$ -	$ -	$ 877,274.85
3	Distribution Integrity	$ 1,206,294.33	$ -	$ 1,206,294.33	$ 87,121,609.01
4	Transmission Integrity	$ 3,705,074.27	$ -	$ 3,705,074.27	$ 214,976,313.63
5	Total	$ 5,063,264.70	$ -	$ 5,063,264.70	$ 311,068,817.02
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.80%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 5,063,264.70	$ -	$ 5,063,264.70	$ 334,604,252.33
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 5,063,264.70**	**$ -**	**$ 5,063,264.70**	**$ 301,704,252.33**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage Year 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 2

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	November 2019
1	TIMP-Transmission Integrity	F0228443	17	Line ILI Retrofit	3,984.10
2	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	1,086,562.91
3	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	18,133.69
4	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	78,436.46
5	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	4,455.00
6	TIMP-Transmission Integrity	FP1734119	17	Line 307 Replacement	494,962.87
7	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	(32,994.63)
8	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	16,473.74
9	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	2,035,060.13
10	DIMP-Distribution Integrity	F0215064	17	Elizabethan Rd Valve Replacement	(494.08)
11	DIMP-Distribution Integrity	F0215066	17	Maplewood Rd Valve	2,072.97
12	DIMP-Distribution Integrity	F0222124	17	Harding Pl & Granny White Pk Valve	150.06
13	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	7,484.61
14	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	140,470.43
15	DIMP-Distribution Integrity	F0224339	17	Greenbrier Main Replacement	57,281.53
16	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	26,039.93
17	DIMP-Distribution Integrity	F0224357	17	Patton Ave	52,270.33
18	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	62,862.49
19	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	1,253.68
20	DIMP-Distribution Integrity	F0225786	17	Woodcrest Leak Repair	5,493.86
21	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	787,418.68
22	DIMP-Distribution Integrity	F0227045	17	Highway 76 Valve Replacement	(968.34)
23	DIMP-Distribution Integrity	F0228466	17	Dr. Walter S Davis Valve Removal	(5,745.88)
24	DIMP-Distribution Integrity	F0229053	17	Culvert Street Creek Bore	(19,739.36)
25	DIMP-Distribution Integrity	F0229092	17	39th Ave North	215.04
26	DIMP-Distribution Integrity	FP1733615	17	Sutton Hill Rd - Replacement	(786.01)
27	DIMP-Distribution Integrity	FP1733639	17	Morena St - Insertion	(1,381.54)
28	DIMP-Distribution Integrity	FP1733763	17	Harding Place	7,960.65
29	DIMP-Distribution Integrity	FP1733764	17	Sunnyside Drive	(1,510.70)
30	DIMP-Distribution Integrity	FP1734378	17	Overton Lea DIMP	(5,146.33)
31	DIMP-Distribution Integrity	FP1734401	17	Tallwood Dr. Across Briley Pkwy	45,304.43
32	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	71,895.31
33	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	138,760.95
34	DIMP-Distribution Integrity	FP1734432	17	Visco Dt	(175,927.43)
35	DIMP-Distribution Integrity	FP1734672	17	12th Ave N at Grundy St.	(2,055.01)
36	DIMP-Distribution Integrity	FP1734690	17	Belmont Pit Regulator Replacement a	(4,511.90)
37	DIMP-Distribution Integrity	FP1734692	17	California Ave #1817	(2,468.10)
38	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	33,412.64
39	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	4,940.32
40	DIMP-Distribution Integrity	FP1734812	17	Haverford Ave.	(10,680.38)
41	DIMP-Distribution Integrity	FP1734824	17	Childrens Way	(7,578.52)
42	CCRR-Corrosion Control	F0214742	17	Dickerson Rd @ Shevel St	(5,097.12)
43	CCRR-Corrosion Control	F0228699	17	Nashville Anode Bed	997.21
44	CCRR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	8,378.19
45	CCRR-Corrosion Control	F0229657	17	461 Paragon Mills Rd. Bridge Attach	50,067.80
46	CCRR-Corrosion Control	F0229673	17	Overton Rd. at 685 Hill Rd. Bridge	29,868.64
47	CCRR-Corrosion Control	F0229691	17	Harding Road at Richland Creek and	21,218.54
48	CCRR-Corrosion Control	F0229716	17	Bridge Attach 4578 Stewart Ferry	46,462.84
49	**Total (unallocated)**				**$ 5,063,264.70**
	subtotal: TN Direct (unallocated)				*$ 5,063,264.70*
	subtotal: CO-3 (unallocated)				*$ -*
					$ 5,063,264.70

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 3

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			Nov-19
1	Beginning Balance	*Prior Month's IMR Report*	$ (6,248,078.36)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	2,247,984.34
3	(Collections from IM Adjustment)	*see Separate Schedule*	(2,639,203.09)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(6,639,297.11)
5	Average Balance	*(Line 1 + Line 4) /2*	(6,443,687.74)
6	Accrued Interest	*Line 5 * Line 9*	(29,106.14)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (6,668,403.25)
8	Applicable Annual Interest Rate	*same as for ACA*	0.054200
9	Monthly Interest Rate	*Line 8 / 12*	0.004517
10	Actual GL #0253139 EOM Balance	*per GL*	$ (6,668,403.25)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	2,247,984.34
47136 0480000 GA489 PTOP 0526 RESVAL	(1,340,787.78)
47136 0481200 GA489 PTOP 0526 COMSTD	(701,371.11)
47136 0481000 GA489 PTOP 0526 INDSLS	(30,325.31)
47136 0483011 GA489 PTOP 0526 GASRSL	(629.44)
47136 0489000 GA489 PTOP 0526 BOTHRV	(174,870.70)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(29,106.14)
47136 0431150 GA626 PTOP 0526	29,106.14

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 4

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

Line No.		Nov-19 IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
1	Residential (301)	0.14605		10,086,725		1,473,166.19
2	Small General Sales (302)	0.12759		4,731,896		603,742.61
3	Medium General Sales (352)	0.12759		1,998,425		254,979.05
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		672		85.74
5	Firm Lg General Sales (303)	0.05667		969,311		54,930.85
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		32,643		1,849.88
7	Firm Lg General Transportation (313)	0.05667		1,976,390		112,002.02
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		135,685		7,689.27
9	Firm Resale (310)	0.05667		4,918		278.70
10	Interruptible Lg General Sales (304)	0.01417		34,525		489.22
11	Interruptible Lg General Transportation (314)	0.01417		9,173,575		129,989.56
12	**Total**					**$ 2,639,203.09**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	1,473,166.19
47136 0481200 GA489 PTOP 0526 COMSTD	603,742.61
47136 0481200 GA489 PTOP 0526 COMSTD	255,064.79
47136 0481000 GA489 PTOP 0526 INDSLS	56,780.73
47136 0489000 GA489 PTOP 0526 BOTHRV	119,691.29
47136 0483011 GA489 PTOP 0526 GASRSL	278.70
47136 0481000 GA489 PTOP 0526 INDSLS	489.22
47136 0489000 GA489 PTOP 0526 BOTHRV	129,989.56
47136 0253139 GA489 PTOP	(2,639,203.09)
	-

waller

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Electronically Filed in TPUC Docket Room February 14, 2020 1:31 p.m.

February 14, 2020

Via Hand Delivery and Email

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending December 31, 2019.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended December 31, 2019.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy of each via our office courier.

Very truly yours,

Paul S. Davidson /dg

Paul S. Davidson

Enclosures

cc: Pia Powers
Bruce Barkley
Michelle Mairs
Emily Knight

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD DR 1 Item 24a

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8 — December 2019 Capital Expenditure [1]	Current Vintage Year: Vintage Year 8 — Prior Cumulative Capital Expenditure [2]	Current Vintage Year: Vintage Year 8 — Cumulative Capital Expenditure as of December 2019 [3]	All Vintage Years — Cumulative Capital Expenditure as of December 2019 [6]
	TN Direct				
1	Corrosion Control	$ 361,088.31	$ 151,896.10	$ 512,984.41	$ 8,454,707.84
2	Casing Remediation	$ -	$ -	$ -	$ 877,274.85
3	Distribution Integrity	$ 827,967.59	$ 1,206,294.33	$ 2,034,261.92	$ 87,949,576.60
4	Transmission Integrity	$ 431,550.95	$ 3,705,074.27	$ 4,136,625.22	$ 215,407,864.58
5	Total	$ 1,620,606.85	$ 5,063,264.70	$ 6,683,871.55	$ 312,689,423.87
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.80%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 1,620,606.85	$ 5,063,264.70	$ 6,683,871.55	$ 336,224,859.18
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 1,620,606.85**	**$ 5,063,264.70**	**$ 6,683,871.55**	**$ 303,324,859.18**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc. Schedule 2
Integrity Management Rider
State of Tennessee

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	December 2019
1	CORR-Corrosion Control	F0228699	17	Nashville Anode Bed	453.30
2	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	66.03
3	CORR-Corrosion Control	F0229691	17	Harding Road at Richland Creek and	76.12
4	CORR-Corrosion Control	F0229673	17	Overton Rd. at 685 Hill Rd. Bridge	107.16
5	CORR-Corrosion Control	F0230478	17	Bridge Attach Donelson Pike & I-40	46,411.57
6	CORR-Corrosion Control	F0230546	17	Bridge Attach Stewart FerryPike I40	60,488.13
7	CORR-Corrosion Control	F0229694	17	Bridge Attach Mt. Juliet Rd & I-40	44,591.57
8	CORR-Corrosion Control	F0229701	17	Bridge Attach New Hope RD & I-40	43,513.78
9	CORR-Corrosion Control	F0230547	17	Bridge Attach Hwy96& I40 Fairview	79,640.30
10	CORR-Corrosion Control	F0229672	17	Lebanon Rd. Over Briley Parkway Bri	34,639.43
11	CORR-Corrosion Control	F0229681	17	East Trinity Lane at Ellington Park	29,438.29
12	CORR-Corrosion Control	F0229717	17	Bridge Attach Ashland City Marks	21,662.63
13	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	7,533.57
14	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	470.80
15	DIMP-Distribution Integrity	FP1733763	17	Harding Place	1,632.79
16	DIMP-Distribution Integrity	FP1734694	17	Forrest St.	2,663.43
17	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	12,348.24
18	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	70,320.89
19	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	95,494.57
20	DIMP-Distribution Integrity	F0224339	17	Greenbrier Main Replacement	103,738.88
21	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	284.90
22	DIMP-Distribution Integrity	F0229053	17	Culvert Street Creek Bore	10,242.72
23	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	226,190.46
24	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	2,706.66
25	DIMP-Distribution Integrity	FP1734401	17	Tallwood Dr. Across Briley Pkwy	154,214.00
26	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	11,056.49
27	DIMP-Distribution Integrity	F0229092	17	39th Ave North	12,063.87
28	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	2,693.43
29	DIMP-Distribution Integrity	F0225786	17	Woodcrest Leak Repair	55.09
30	DIMP-Distribution Integrity	FP1734688	17	Abbott Martin @ Walnut Dr.	234.47
31	DIMP-Distribution Integrity	F0224357	17	Patton Ave	75,023.24
32	DIMP-Distribution Integrity	F0215066	17	Maplewood Rd Valve	35,806.62
33	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	3,192.47
34	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	10,161.12
35	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	145,017.74
36	TIMP-Transmission Integrity	F0228443	17	Line ILI Retrofit	1,757.11
37	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	36,933.65
38	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	(141,573.29)
39	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	143,280.67
40	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	167,797.99
41	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	68,175.96
42	**Total (unallocated)**				**$ 1,620,606.85**
	subtotal: TN Direct (unallocated)				*$ 1,620,606.85*
	subtotal: CO-3 (unallocated)				*$ -*
					$ 1,620,606.85

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			**Dec-19**
1	Beginning Balance	*Prior Month's IMR Report*	$ (6,668,403.25)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	3,578,764.04
3	(Collections from IM Adjustment)	*see Separate Schedule*	(4,335,954.72)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(7,425,593.93)
5	Average Balance	*(Line 1 + Line 4) /2*	(7,046,998.59)
6	Accrued Interest	*Line 5 * Line 9*	(31,831.29)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (7,457,425.22)
8	Applicable Annual Interest Rate	*same as for ACA*	0.054200
9	Monthly Interest Rate	*Line 8 / 12*	0.004517
10	Actual GL #0253139 EOM Balance	*per GL*	$ (7,457,425.22)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	3,578,764.04
47136 0480000 GA489 PTOP 0526 RESVAL	(2,134,518.02)
47136 0481200 GA489 PTOP 0526 COMSTD	(1,116,574.38)
47136 0481000 GA489 PTOP 0526 INDSLS	(48,277.53)
47136 0483011 GA489 PTOP 0526 GASRSL	(1,002.05)
47136 0489000 GA489 PTOP 0526 BOTHRV	(278,392.06)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(31,831.29)
47136 0431150 GA626 PTOP 0526	31,831.29

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 4

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

Line No.		Dec-19 IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
1	Residential (301)	0.14605		18,333,507		2,677,608.70
2	Small General Sales (302)	0.12759		7,591,560		968,607.14
3	Medium General Sales (352)	0.12759		2,968,945		378,807.69
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		854		108.96
5	Firm Lg General Sales (303)	0.05667		967,154		54,808.62
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		33,162		1,879.29
7	Firm Lg General Transportation (313)	0.05667		2,043,436		115,801.52
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		131,294		7,440.43
9	Firm Resale (310)	0.05667		5,103		289.19
10	Interruptible Lg General Sales (304)	0.01417		34,024		482.12
11	Interruptible Lg General Transportation (314)	0.01417		9,182,855		130,121.06
12	**Total**					**$ 4,335,954.72**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	2,677,608.70
47136 0481200 GA489 PTOP 0526 COMSTD	968,607.14
47136 0481200 GA489 PTOP 0526 COMSTD	378,916.65
47136 0481000 GA489 PTOP 0526 INDSLS	56,687.91
47136 0489000 GA489 PTOP 0526 BOTHRV	123,241.95
47136 0483011 GA489 PTOP 0526 GASRSL	289.19
47136 0481000 GA489 PTOP 0526 INDSLS	482.12
47136 0489000 GA489 PTOP 0526 BOTHRV	130,121.06
47136 0253139 GA489 PTOP	(4,335,954.72)
	-

Electronically Filed in TPUC Docket Room on March 13, 2020 at 1:08 p.m

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March 13, 2020

Via Hand Delivery and Email

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: **Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118**

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending January 31, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended January 31, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy of each via our office courier.

Very truly yours,

Paul S. Davidson

Paul S. Davidson

PSD:cdg
Enclosures

cc: Pia Powers
Bruce Barkley
Michelle Mairs
Emily Knight
James Jeffries

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		January 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of January 2020 [3]	Cumulative Capital Expenditure as of January 2020 [6]
	TN Direct				
1	Corrosion Control	$ 10,052.64	$ 512,984.41	$ 523,037.05	$ 8,464,760.48
2	Casing Remediation	$ -	$ -	$ -	$ 877,274.85
3	Distribution Integrity	$ 1,169,460.32	$ 2,034,261.92	$ 3,203,722.24	$ 89,119,036.92
4	Transmission Integrity	$ 745,666.62	$ 4,136,625.22	$ 4,882,291.84	$ 216,153,531.20
5	Total	$ 1,925,179.58	$ 6,683,871.55	$ 8,609,051.13	$ 314,614,603.45
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 1,925,179.58	$ 6,683,871.55	$ 8,609,051.13	$ 338,150,038.76
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 1,925,179.58**	**$ 6,683,871.55**	**$ 8,609,051.13**	**$ 305,250,038.76**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc. Schedule 2
Integrity Management Rider
State of Tennessee

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	January 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	823.84
2	CORR-Corrosion Control	F0230547	17	Bridge Attach Hwy96& I40 Fairview	1,031.54
3	CORR-Corrosion Control	F0230478	17	Bridge Attach Donelson Pike & I-40	137.12
4	CORR-Corrosion Control	F0230546	17	Bridge Attach Stewart FerryPike I40	178.71
5	CORR-Corrosion Control	F0229694	17	Bridge Attach Mt. Juliet Rd & I-40	296.95
6	CORR-Corrosion Control	F0229672	17	Lebanon Rd. Over Briley Parkway Bri	331.63
7	CORR-Corrosion Control	F0229681	17	East Trinity Lane at Ellington Park	379.39
8	CORR-Corrosion Control	F0229717	17	Bridge Attach Ashland City Marks	202.65
9	CORR-Corrosion Control	F0229701	17	Bridge Attach New Hope RD & I-40	128.56
10	CORR-Corrosion Control	F0229695	17	Bridge Attach Mufreesboro Rd	6,542.25
11	DIMP-Distribution Integrity	F0221329	17	10th Ave N Valve Replacement	7,278.97
12	DIMP-Distribution Integrity	F0221773	17	Walton Lane Valve Replacements	51,669.63
13	DIMP-Distribution Integrity	FP1734694	17	Forrest St.	3,181.27
14	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	243.29
15	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	85,120.99
16	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	794.41
17	DIMP-Distribution Integrity	F0224357	17	Patton Ave	83,334.44
18	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	44,330.99
19	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	245,171.08
20	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	82,107.94
21	DIMP-Distribution Integrity	F0224339	17	Greenbrier Main Replacement	3,319.18
22	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	(82,291.88)
23	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	345,526.46
24	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	115,444.28
25	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	106,725.88
26	DIMP-Distribution Integrity	FP1734401	17	Tallwood Dr. Across Briley Pkwy	5,140.07
27	DIMP-Distribution Integrity	F0229092	17	39th Ave North	80.33
28	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	9,213.95
29	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	57,360.16
30	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	5,708.88
31	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	591,931.58
32	TIMP-Transmission Integrity	F0228443	17	Line ILI Retrofit	871.45
33	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	78,784.28
34	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	36,229.98
35	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	15,797.81
36	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	13,133.53
37	TIMP-Transmission Integrity	F0231370	17	Line 320 ILI Retrofit	6,758.85
38	TIMP-Transmission Integrity	FP1734119	17	Line 307 Replacement	(25,891.41)
39	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	28,050.55
40	**Total (unallocated)**				**$ 1,925,179.58**
	subtotal: TN Direct (unallocated)				*$ 1,925,179.58*
	subtotal: CO-3 (unallocated)				*$ -*
					$ 1,925,179.58

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			**Jan-20**
1	Beginning Balance	*Prior Month's IMR Report*	$ (7,457,425.22)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	4,456,561.59
3	(Collections from IM Adjustment)	*see Separate Schedule*	(4,591,595.97)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(7,592,459.60)
5	Average Balance	*(Line 1 + Line 4) /2*	(7,524,942.41)
6	Accrued Interest	*Line 5 * Line 9*	(31,100.59)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (7,623,560.19)
8	Applicable Annual Interest Rate	*same as for ACA*	0.049600
9	Monthly Interest Rate	*Line 8 / 12*	0.004133
10	Actual GL #0253139 EOM Balance	*per GL*	$ (7,623,560.19)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	4,456,561.59
47136 0480000 GA489 PTOP 0526 RESVAL	(2,658,071.60)
47136 0481200 GA489 PTOP 0526 COMSTD	(1,390,447.22)
47136 0481000 GA489 PTOP 0526 INDSLS	(60,119.01)
47136 0483011 GA489 PTOP 0526 GASRSL	(1,247.84)
47136 0489000 GA489 PTOP 0526 BOTHRV	(346,675.92)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(31,100.59)
47136 0431150 GA626 PTOP 0526	31,100.59

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		Jan-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.14605		19,309,797		2,820,195.85
2	Small General Sales (302)	0.12759		8,192,387		1,045,266.66
3	Medium General Sales (352)	0.12759		3,066,638		391,272.34
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		749		95.56
5	Firm Lg General Sales (303)	0.05667		1,078,655		61,127.38
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		29,968		1,698.29
7	Firm Lg General Transportation (313)	0.05667		2,213,820		125,457.18
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		137,809		7,809.64
9	Firm Resale (310)	0.05667		6,129		347.33
10	Interruptible Lg General Sales (304)	0.01417		28,722		406.99
11	Interruptible Lg General Transportation (314)	0.01417		9,733,151		137,918.75
12	**Total**					**$ 4,591,595.97**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	2,820,195.85
47136 0481200 GA489 PTOP 0526 COMSTD	1,045,266.66
47136 0481200 GA489 PTOP 0526 COMSTD	391,367.90
47136 0481000 GA489 PTOP 0526 INDSLS	62,825.67
47136 0489000 GA489 PTOP 0526 BOTHRV	133,266.82
47136 0483011 GA489 PTOP 0526 GASRSL	347.33
47136 0481000 GA489 PTOP 0526 INDSLS	406.99
47136 0489000 GA489 PTOP 0526 BOTHRV	137,918.75
47136 0253139 GA489 PTOP	(4,591,595.97)
	-

Electronically Filed in TPUC Docket Room on April 14, 2020 at 12:54 p.m.

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April 14, 2020

Via Email and U.S. Mail

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed please find the original and five (5) copies Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending February 29, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended February 29, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Tory Lawless. Please file the original and provide us a "filed" stamped copy of in the enclosed self-addressed stamped envelope.

Very truly yours,

/s/ Paul Davidson

Paul S. Davidson

Enclosures

cc: Emily Knight
Pia Powers
Bruce Barkley
James Jeffries

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD DR 1 Item 24a

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		February 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of February 2020 [3]	Cumulative Capital Expenditure as of February 2020 [6]
	TN Direct				
1	Corrosion Control	$ 495.84	$ 523,037.05	$ 523,532.89	$ 8,465,256.32
2	Casing Remediation	$ -	$ -	$ -	$ 877,274.85
3	Distribution Integrity	$ 706,183.64	$ 3,203,722.24	$ 3,909,905.88	$ 89,825,220.56
4	Transmission Integrity	$ 715,739.08	$ 4,882,291.84	$ 5,598,030.92	$ 216,869,270.28
5	Total	$ 1,422,418.56	$ 8,609,051.13	$ 10,031,469.69	$ 316,037,022.01
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 1,422,418.56	$ 8,609,051.13	$ 10,031,469.69	$ 339,572,457.32
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 1,422,418.56**	**$ 8,609,051.13**	**$ 10,031,469.69**	**$ 306,672,457.32**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 2

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	February 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	60.71
2	CORR-Corrosion Control	F0229695	17	Bridge Attach Mufreesboro Rd	198.55
3	CORR-Corrosion Control	F0230547	17	Bridge Attach Hwy96& I40 Fairview	236.58
4	DIMP-Distribution Integrity	F0221354	17	Davidson Drive @ Charlotte Pike Valve	4,897.47
5	DIMP-Distribution Integrity	F0221773	17	Walton Lane Valve Replacements	12,249.67
6	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	50,423.48
7	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	18,482.26
8	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	206,968.53
9	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	162,188.97
10	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	4,125.92
11	DIMP-Distribution Integrity	F0224357	17	Patton Ave	40,336.92
12	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	871.57
13	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	19.51
14	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	16,259.28
15	DIMP-Distribution Integrity	F0229092	17	39th Ave North	14,015.17
16	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	6,912.75
17	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	77,258.90
18	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	44,130.40
19	DIMP-Distribution Integrity	FP1734694	17	Forrest St.	54.19
20	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	37,155.63
21	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	9,833.02
22	TIMP-Transmission Integrity	F0228443	17	Line ILI Retrofit	449.58
23	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	1,837.25
24	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	7,329.88
25	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	524.47
26	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	375,821.90
27	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	36,822.90
28	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	66,070.38
29	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	226,882.72
30	**Total (unallocated)**				**$ 1,422,418.56**

subtotal: TN Direct (unallocated)	*$ 1,422,418.56*
subtotal: CO-3 (unallocated)	*$ -*
	$ 1,422,418.56

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			**Feb-20**
1	Beginning Balance	*Prior Month's IMR Report*	$ (7,623,560.19)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	4,240,902.01
3	(Collections from IM Adjustment)	*see Separate Schedule*	(4,940,454.02)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(8,323,112.20)
5	Average Balance	*(Line 1 + Line 4) /2*	(7,973,336.20)
6	Accrued Interest	*Line 5 * Line 9*	(32,953.80)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (8,356,066.00)
8	Applicable Annual Interest Rate	*same as for ACA*	0.049600
9	Monthly Interest Rate	*Line 8 / 12*	0.004133
10	Actual GL #0253139 EOM Balance	*per GL*	$ (8,356,066.00)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue

47136 0253139 GA489 PTOP	4,240,902.01
47136 0480000 GA489 PTOP 0526 RESVAL	(2,529,443.60)
47136 0481200 GA489 PTOP 0526 COMSTD	(1,323,161.42)
47136 0481000 GA489 PTOP 0526 INDSLS	(57,209.77)
47136 0483011 GA489 PTOP 0526 GASRSL	(1,187.45)
47136 0489000 GA489 PTOP 0526 BOTHRV	(329,899.77)

Journal Entry: To Record Interest

47136 0253139 GA626 PTOP	(32,953.80)
47136 0431150 GA626 PTOP 0526	32,953.80

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		Feb-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.14605		21,228,260		3,100,387.37
2	Small General Sales (302)	0.12759		8,638,174		1,102,144.62
3	Medium General Sales (352)	0.12759		3,240,669		413,476.96
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		172		21.95
5	Firm Lg General Sales (303)	0.05667		1,054,742		59,772.23
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		27,375		1,551.34
7	Firm Lg General Transportation (313)	0.05667		2,181,191		123,608.09
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		126,824		7,187.12
9	Firm Resale (310)	0.05667		5,895		334.07
10	Interruptible Lg General Sales (304)	0.01417		29,104		412.40
11	Interruptible Lg General Transportation (314)	0.01417		9,284,253		131,557.87
12	**Total**					**$ 4,940,454.02**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	3,100,387.37
47136 0481200 GA489 PTOP 0526 COMSTD	1,102,144.62
47136 0481200 GA489 PTOP 0526 COMSTD	413,498.91
47136 0481000 GA489 PTOP 0526 INDSLS	61,323.57
47136 0489000 GA489 PTOP 0526 BOTHRV	130,795.21
47136 0483011 GA489 PTOP 0526 GASRSL	334.07
47136 0481000 GA489 PTOP 0526 INDSLS	412.40
47136 0489000 GA489 PTOP 0526 BOTHRV	131,557.87
47136 0253139 GA489 PTOP	(4,940,454.02)
	-

Electronically Filed in TPUC Docket Room on May 13, 2020 at 11:42 a.m.

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May 13, 2020

Via Email and U.S. Mail

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending March 31, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended March 31, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy of each either by email, or return copy via U.S. Mail. I have enclosed a self-addressed, postage prepaid envelope should you choose the mail option.

Very truly yours,

Paul S. Davidson

PSD:cdg

cc: Bruce Barkley
Pia Powers
Michelle Mairs
Alex Bradley
Daniel Whitaker
James Jeffrie

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		March 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of March 2020 [3]	Cumulative Capital Expenditure as of March 2020 [6]
	TN Direct				
1	Corrosion Control	$ 36.00	$ 523,532.89	$ 523,568.89	$ 8,465,292.32
2	Casing Remediation	$ (9.64)	$ -	$ (9.64)	$ 877,265.21
3	Distribution Integrity	$ 1,077,495.50	$ 3,909,905.88	$ 4,987,401.38	$ 90,902,716.06
4	Transmission Integrity	$ 8,463,726.96	$ 5,598,030.92	$ 14,061,757.88	$ 225,332,997.24
5	Total	$ 9,541,248.82	$ 10,031,469.69	$ 19,572,718.51	$ 325,578,270.83
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 9,541,248.82	$ 10,031,469.69	$ 19,572,718.51	$ 349,113,706.14
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 9,541,248.82**	**$ 10,031,469.69**	**$ 19,572,718.51**	**$ 316,213,706.14**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 2

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	March 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	68.74
2	CORR-Corrosion Control	F0229672	17	Lebanon Rd. Over Briley Parkway Bri	(19.72)
3	CORR-Corrosion Control	F0229681	17	East Trinity Lane at Ellington Park	(19.80)
4	CORR-Corrosion Control	F0229694	17	Bridge Attach Mt. Juliet Rd & I-40	(11.73)
5	CORR-Corrosion Control	F0229695	17	Bridge Attach Mufreesboro Rd	44.10
6	CORR-Corrosion Control	F0229717	17	Bridge Attach Ashland City Marks	(7.26)
7	CORR-Corrosion Control	F0230547	17	Bridge Attach Hwy96& I40 Fairview	(18.33)
8	CSNG-Casing & Remediation	FP1734401	17	Tallwood Dr. Across Briley Pkwy	(9.64)
9	DIMP-Distribution Integrity	F0221329	17	10th Ave N Valve Replacement	(11.05)
10	DIMP-Distribution Integrity	F0221354	17	Davidson Drive @ Charlotte Pike Valve	64,636.57
11	DIMP-Distribution Integrity	F0221773	17	Walton Lane Valve Replacements	3,558.20
12	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	50,365.35
13	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	7,768.65
14	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	353,503.58
15	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	276,846.54
16	DIMP-Distribution Integrity	F0224339	17	Greenbrier Main Replacement	(25.11)
17	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	20,807.79
18	DIMP-Distribution Integrity	F0224357	17	Patton Ave	116,928.14
19	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	15,832.29
20	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	1,056.15
21	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	12,553.03
22	DIMP-Distribution Integrity	F0229092	17	39th Ave North	3,308.07
23	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	10,412.01
24	DIMP-Distribution Integrity	FP1733931	17	Shelby Park RR Bridge Project	30,464.96
25	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	(5.25)
26	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	22,610.89
27	DIMP-Distribution Integrity	FP1734694	17	Forrest St.	(15.74)
28	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	65,484.40
29	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	21,416.03
30	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	273.22
31	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	273.22
32	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	6,247.13
33	TIMP-Transmission Integrity	F0231370	17	Line 320 ILI Retrofit	319.60
34	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	60,407.78
35	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	12,683.16
36	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	56,358.72
37	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	8,327,164.13

38	**Total (unallocated)**	**$ 9,541,248.82**
	subtotal: TN Direct (unallocated)	*$ 9,541,248.82*
	subtotal: CO-3 (unallocated)	*$ -*
		$ 9,541,248.82

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			**Mar-20**
1	Beginning Balance	*Prior Month's IMR Report*	$ (8,356,066.00)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	3,202,192.54
3	(Collections from IM Adjustment)	*see Separate Schedule*	(4,085,841.64)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(9,239,715.10)
5	Average Balance	*(Line 1 + Line 4) /2*	(8,797,890.55)
6	Accrued Interest	*Line 5 * Line 9*	(36,361.68)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (9,276,076.78)
8	Applicable Annual Interest Rate	*same as for ACA*	0.049600
9	Monthly Interest Rate	*Line 8 / 12*	0.004133
10	Actual GL #0253139 EOM Balance	*per GL*	$ (9,276,076.78)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	3,202,192.54
47136 0480000 GA489 PTOP 0526 RESVAL	(1,909,915.72)
47136 0481200 GA489 PTOP 0526 COMSTD	(999,084.07)
47136 0481000 GA489 PTOP 0526 INDSLS	(43,197.58)
47136 0483011 GA489 PTOP 0526 GASRSL	(896.61)
47136 0489000 GA489 PTOP 0526 BOTHRV	(249,098.56)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(36,361.68)
47136 0431150 GA626 PTOP 0526	36,361.68

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		Mar-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.14605		17,708,962		2,586,393.90
2	Small General Sales (302)	0.12759		7,138,739		910,831.71
3	Medium General Sales (352)	0.12759		2,609,351		332,927.09
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		236		30.11
5	Firm Lg General Sales (303)	0.05667		616,894		34,959.38
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		27,694		1,569.42
7	Firm Lg General Transportation (313)	0.05667		1,728,185		97,936.24
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		136,338		7,726.27
9	Firm Resale (310)	0.05667		3,338		189.16
10	Interruptible Lg General Sales (304)	0.01417		19,015		269.44
11	Interruptible Lg General Transportation (314)	0.01417		7,975,224		113,008.92
12	**Total**					**$ 4,085,841.64**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	2,586,393.90
47136 0481200 GA489 PTOP 0526 COMSTD	910,831.71
47136 0481200 GA489 PTOP 0526 COMSTD	332,957.20
47136 0481000 GA489 PTOP 0526 INDSLS	36,528.80
47136 0489000 GA489 PTOP 0526 BOTHRV	105,662.51
47136 0483011 GA489 PTOP 0526 GASRSL	189.16
47136 0481000 GA489 PTOP 0526 INDSLS	269.44
47136 0489000 GA489 PTOP 0526 BOTHRV	113,008.92
47136 0253139 GA489 PTOP	(4,085,841.64)
	-

Electronically Filed in TPUC Docket Room on June 15, 2020 at 1:06 p.m.

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June 15, 2020

Via Email and U.S. Mail

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending April 30, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended April 30, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy of each either by email, or return copy via U.S. Mail. I have enclosed a self-addressed, postage prepaid envelope should you choose the mail option.

Very truly yours,

Paul S. Davidson

PSD:cdg

cc: Bruce Barkley
Pia Powers
Michelle Mairs
Alex Bradley
Daniel Whitaker
James Jeffries

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		April 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of April 2020 [3]	Cumulative Capital Expenditure as of April 2020 [6]
	TN Direct				
1	Corrosion Control	$ 7,626.22	$ 523,568.89	$ 531,195.11	$ 8,472,918.54
2	Casing Remediation	$ 425.70	$ (9.64)	$ 416.06	$ 877,690.91
3	Distribution Integrity	$ 1,501,352.06	$ 4,987,401.38	$ 6,488,753.44	$ 92,404,068.12
4	Transmission Integrity	$ 5,447,540.70	$ 14,061,757.88	$ 19,509,298.58	$ 230,780,537.94
5	Total	$ 6,956,944.68	$ 19,572,718.51	$ 26,529,663.19	$ 332,535,215.51
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 6,956,944.68	$ 19,572,718.51	$ 26,529,663.19	$ 356,070,650.82
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 6,956,944.68**	**$ 19,572,718.51**	**$ 26,529,663.19**	**$ 323,170,650.82**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc. Schedule 2
Integrity Management Rider
State of Tennessee

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	April 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	2,401.39
2	CORR-Corrosion Control	F0229672	17	Lebanon Rd. Over Briley Parkway Bri	17.12
3	CORR-Corrosion Control	F0229681	17	East Trinity Lane at Ellington Park	23.96
4	CORR-Corrosion Control	F0229694	17	Bridge Attach Mt. Juliet Rd & I-40	22.50
5	CORR-Corrosion Control	F0229695	17	Bridge Attach Mufreesboro Rd	44.39
6	CORR-Corrosion Control	F0229701	17	Bridge Attach New Hope RD & I-40	21.29
7	CORR-Corrosion Control	F0230478	17	Bridge Attach Donelson Pike & I-40	22.50
8	CORR-Corrosion Control	F0230546	17	Bridge Attach Stewart FerryPike I40	59.95
9	CORR-Corrosion Control	FP1708010	17	Nashville Anodes	5,013.12
10	CSNG-Casing & Remediation	F0231471	17	44th Ave N @ I-40 - 8" Pipe	425.70
11	DIMP-Distribution Integrity	F0221354	17	Davidson Drive @ Charlotte Pike Valve	21,936.66
12	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	5,556.51
13	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	728.61
14	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	461,387.17
15	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	111,753.47
16	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	10,746.47
17	DIMP-Distribution Integrity	F0224357	17	Patton Ave	15,930.43
18	DIMP-Distribution Integrity	F0224363	17	Maxon Ave Main Replacement	339.07
19	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	342.44
20	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	27,673.60
21	DIMP-Distribution Integrity	F0229092	17	39th Ave North	21,531.47
22	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	324,690.10
23	DIMP-Distribution Integrity	F0230684	17	Bordeaux Bridge Expainsion Joint -	283.84
24	DIMP-Distribution Integrity	F0231296	17	Ed Temple Blvd DIMP	219,096.04
25	DIMP-Distribution Integrity	F0231458	17	Charlotte Ave Casing Retirement	6,467.32
26	DIMP-Distribution Integrity	FP1734419	17	Rosedale Ave	(1,476.73)
27	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	155,388.73
28	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	103,376.62
29	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	15,600.24
30	TIMP-Transmission Integrity	F0229405	17	Line 203 Anomalies ILI Excavations	411.69
31	TIMP-Transmission Integrity	F0230575	17	Line 384 - Valve Automation - Stati	212.86
32	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	282.92
33	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	1,854.00
34	TIMP-Transmission Integrity	F0231370	17	Line 320 ILI Retrofit	544.25
35	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	(3,826.64)
36	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	86,693.00
37	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	114,426.69
38	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	5,246,941.93
39	**Total (unallocated)**				**$ 6,956,944.68**
	subtotal: TN Direct (unallocated)				*$ 6,956,944.68*
	subtotal: CO-3 (unallocated)				*$ -*
					$ 6,956,944.68

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			**Apr-20**
1	Beginning Balance	*Prior Month's IMR Report*	$ (9,276,076.78)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	2,069,310.80
3	(Collections from IM Adjustment)	*see Separate Schedule*	(2,206,225.68)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(9,412,991.66)
5	Average Balance	*(Line 1 + Line 4) /2*	(9,344,534.22)
6	Accrued Interest	*Line 5 * Line 9*	(36,985.67)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (9,449,977.33)
8	Applicable Annual Interest Rate	*same as for ACA*	0.047500
9	Monthly Interest Rate	*Line 8 / 12*	0.003958
10	Actual GL #0253139 EOM Balance	*per GL*	$ (9,449,977.33)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	2,069,310.80
47136 0480000 GA489 PTOP 0526 RESVAL	(1,234,219.73)
47136 0481200 GA489 PTOP 0526 COMSTD	(645,624.97)
47136 0481000 GA489 PTOP 0526 INDSLS	(27,915.00)
47136 0483011 GA489 PTOP 0526 GASRSL	(579.41)
47136 0489000 GA489 PTOP 0526 BOTHRV	(160,971.69)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(36,985.67)
47136 0431150 GA626 PTOP 0526	36,985.67

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		Apr-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.14605		9,363,206		1,367,496.24
2	Small General Sales (302)	0.12759		3,484,273		444,558.39
3	Medium General Sales (352)	0.12759		1,429,260		182,359.28
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		129		16.46
5	Firm Lg General Sales (303)	0.05667		407,618		23,099.71
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		12,831		727.13
7	Firm Lg General Transportation (313)	0.05667		1,363,526		77,271.02
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		130,758		7,410.06
9	Firm Resale (310)	0.05667		2,360		133.74
10	Interruptible Lg General Sales (304)	0.01417		15,441		218.80
11	Interruptible Lg General Transportation (314)	0.01417		7,264,280		102,934.85
12	**Total**					**$ 2,206,225.68**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	1,367,496.24
47136 0481200 GA489 PTOP 0526 COMSTD	444,558.39
47136 0481200 GA489 PTOP 0526 COMSTD	182,375.74
47136 0481000 GA489 PTOP 0526 INDSLS	23,826.84
47136 0489000 GA489 PTOP 0526 BOTHRV	84,681.08
47136 0483011 GA489 PTOP 0526 GASRSL	133.74
47136 0481000 GA489 PTOP 0526 INDSLS	218.80
47136 0489000 GA489 PTOP 0526 BOTHRV	102,934.85
47136 0253139 GA489 PTOP	(2,206,225.68)
	-

Electronically Filed in TPUC Docket Room on July 15, 2020 at 9:39 a.m.

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July 14, 2020

Via Hand Delivery and Email

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc.
Integrity Management Rider Monthly Report
Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont") Integrity Management Rider ("IMR") Monthly Report for the month ending May 31, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended May 31, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy via email to my assistant, Denise Guye, at denise.guye@wallerlaw.com.

Very truly yours,

Paul S. Davidson

Enclosures

cc: Bruce Barkley
Pia Powers
Michelle Mairs
Alex Bradley
Daniel Whitaker
James Jeffries

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		May 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of May 2020 [3]	Cumulative Capital Expenditure as of May 2020 [6]
	TN Direct				
1	Corrosion Control	$ 49,528.96	$ 531,195.11	$ 580,724.07	$ 8,522,447.50
2	Casing Remediation	$ 1,948.20	$ 416.06	$ 2,364.26	$ 879,639.11
3	Distribution Integrity	$ 1,684,200.15	$ 6,488,753.44	$ 8,172,953.59	$ 94,088,268.27
4	Transmission Integrity	$ 5,753,598.91	$ 19,509,298.58	$ 25,262,897.49	$ 236,534,136.85
5	Total	$ 7,489,276.22	$ 26,529,663.19	$ 34,018,939.41	$ 340,024,491.73
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 7,489,276.22	$ 26,529,663.19	$ 34,018,939.41	$ 363,559,927.04
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 7,489,276.22**	**$ 26,529,663.19**	**$ 34,018,939.41**	**$ 330,659,927.04**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 2

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	May 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	84.95
2	CORR-Corrosion Control	F0229657	17	461 Paragon Mills Rd. Bridge Attach	56.26
3	CORR-Corrosion Control	F0229695	17	Bridge Attach Mufreesboro Rd	45,951.52
4	CORR-Corrosion Control	FP1708010	17	Nashville Anodes	3,436.23
5	CSNG-Casing & Remediation	F0231471	17	44th Ave N @ I-40 - 8" Pipe	4,111.69
6	CSNG-Casing & Remediation	FP1734401	17	Tallwood Dr. Across Briley Pkwy	(2,163.49)
7	DIMP-Distribution Integrity	F0221354	17	Davidson Drive @ Charlotte Pike Valve	230.76
8	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	838.92
9	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	11,370.50
10	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	385,392.45
11	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	69,116.74
12	DIMP-Distribution Integrity	F0224339	17	Greenbrier Main Replacement	(43,996.74)
13	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	75,695.44
14	DIMP-Distribution Integrity	F0224357	17	Patton Ave	38,767.58
15	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	345.67
16	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	236,764.19
17	DIMP-Distribution Integrity	F0229092	17	39th Ave North	483.75
18	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	330,300.66
19	DIMP-Distribution Integrity	F0230684	17	Bordeaux Bridge Expainsion Joint -	629.95
20	DIMP-Distribution Integrity	F0231296	17	Ed Temple Blvd DIMP	161,220.70
21	DIMP-Distribution Integrity	F0231458	17	Charlotte Ave Casing Retirement	400,259.74
22	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	(22,761.92)
23	DIMP-Distribution Integrity	FP1734694	17	Forrest St.	(3,749.43)
24	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	23,996.57
25	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	19,294.62
26	TIMP-Transmission Integrity	F0230575	17	Line 384 - Valve Automation - Stati	29,152.51
27	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	231.03
28	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	731.64
29	TIMP-Transmission Integrity	F0231370	17	Line 320 ILI Retrofit	96,113.09
30	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	8,748.96
31	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	65,958.05
32	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	5,552,663.63

33	**Total (unallocated)**	**$**	**7,489,276.22**
	subtotal: TN Direct (unallocated)	*$*	*7,489,276.22*
	subtotal: CO-3 (unallocated)	*$*	*-*
		$	***7,489,276.22***

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			Jan-20	Feb-20	Mar-20	Apr-20	May-20	
1	Beginning Balance	*Prior Month's IMR Report*	$ (7,457,425.22)	$ (7,233,932.91)	$ (7,594,055.75)	$ (8,230,956.56)	$ (8,219,821.07)	
2	IMR Revenue Recognition	*Prior Annual IMR Report*	4,845,385.36	4,610,910.03	3,481,575.78	2,249,852.96	1,424,440.83	1/
3	(Collections from IM Adjustment)	*see Separate Schedule*	(4,591,595.97)	(4,940,454.02)	(4,085,841.64)	(2,206,225.68)	(1,624,717.99)	
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(7,203,635.83)	(7,563,476.90)	(8,198,321.61)	(8,187,329.28)	(8,420,098.23)	
5	Average Balance	*(Line 1 + Line 4) /2*	(7,330,530.53)	(7,398,704.91)	(7,896,188.68)	(8,209,142.92)	(8,319,959.65)	
6	Accrued Interest	*Line 5 * Line 9*	(30,297.08)	(30,578.85)	(32,634.95)	(32,491.79)	(32,930.40)	
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (7,233,932.91)	$ (7,594,055.75)	$ (8,230,956.56)	$ (8,219,821.07)	$ (8,453,028.63)	
8	Applicable Annual Interest Rate	*same as for ACA*	0.049600	0.049600	0.049600	0.047500	0.047500	
9	Monthly Interest Rate	*Line 8 / 12*	0.004133	0.004133	0.004133	0.003958	0.003958	
10	Actual GL #0253139 EOM Balance	*per GL*	$ (7,623,560.19)	$ (8,356,066.00)	$ (9,276,076.78)	$ (9,449,977.33)	$ (8,453,028.63)	
11	Variance	*Line 7 - Line 10*	$ 389,627.28	$ 762,010.25	$ 1,045,120.22	$ 1,230,156.26	$ -	2/

Journal Entry: To Record Revenue						
47136 0253139 GA489 PTOP	4,456,561.59	4,240,902.01	3,202,192.54	2,069,310.80	1,424,440.83
47136 0480000 GA489 PTOP 0526 RESVAL	(2,658,071.60)	(2,529,443.60)	(1,909,915.72)	(1,234,219.73)	(849,593.49)
47136 0481200 GA489 PTOP 0526 COMSTD	(1,390,447.22)	(1,323,161.42)	(999,084.07)	(645,624.97)	(444,425.54)
47136 0481000 GA489 PTOP 0526 INDSLS	(60,119.01)	(57,209.77)	(43,197.58)	(27,915.00)	(19,215.71)
47136 0483011 GA489 PTOP 0526 GASRSL	(1,247.84)	(1,187.45)	(896.61)	(579.41)	(398.84)
47136 0489000 GA489 PTOP 0526 BOTHRV	(346,675.92)	(329,899.77)	(249,098.56)	(160,971.69)	(110,807.25)

Journal Entry: To Record Interest					
47136 0253139 GA626 PTOP	(31,100.59)	(32,953.80)	(36,361.68)	(36,985.67)	(32,930.40)
47136 0431150 GA626 PTOP 0526	31,100.59	32,953.80	36,361.68	36,985.67	32,930.40

1/ Pursuant to the TPUC's May 11, 2020 ruling in Docket No. 19-00107, this schedule reflects the approved monthly amortization of the annual Integrity Management Revenue Requirement from Piedmont's 2019 Annual Integrity Management Rider Report, which was filed by the Company on December 11, 2019.

2/ Pursuant to the TPUC's ruling, Piedmont recorded the approved IM Revenue Requirement to its general ledger for January 2020 thru April 2020. It was recorded as a true-up adjustment in May 2020.

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		May-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.14605		6,868,528		1,003,148.51
2	Small General Sales (302)	0.12759		2,376,269		303,188.16
3	Medium General Sales (352)	0.12759		1,014,043		129,381.75
4	Experimental Motor Vehicle Fuel (343/352)	0.12759		1,743		222.39
5	Firm Lg General Sales (303)	0.05667		338,166		19,163.86
6	Experimental Motor Vehicle Fuel (343/303)	0.05667		1,572		89.09
7	Firm Lg General Transportation (313)	0.05667		1,204,863		68,279.57
8	Experimental Motor Vehicle Fuel (343/313)	0.05667		119,620		6,778.87
9	Firm Resale (310)	0.05667		1,575		89.26
10	Interruptible Lg General Sales (304)	0.01417		14,343		203.24
11	Interruptible Lg General Transportation (314)	0.01417		6,645,962		94,173.29
12	**Total**					**$ 1,624,717.99**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	1,003,148.51
47136 0481200 GA489 PTOP 0526 COMSTD	303,188.16
47136 0481200 GA489 PTOP 0526 COMSTD	129,604.14
47136 0481000 GA489 PTOP 0526 INDSLS	19,252.95
47136 0489000 GA489 PTOP 0526 BOTHRV	75,058.44
47136 0483011 GA489 PTOP 0526 GASRSL	89.26
47136 0481000 GA489 PTOP 0526 INDSLS	203.24
47136 0489000 GA489 PTOP 0526 BOTHRV	94,173.29
47136 0253139 GA489 PTOP	(1,624,717.99)
	-

Electronically Filed in TPUC Docket Room on August 14, 2020 at 11:53 a.m.

waller

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August 14, 2020

Via Email and U.S. Mail

Executive Director Earl Taylor
c/o Ectory Lawless
Tennessee Public Utility Commission
502 Deaderick Street, Fourth Floor
Nashville, Tennessee 37243

Re: Piedmont Natural Gas Company, Inc. Integrity Management Rider Monthly Report; Docket No.: 13-00118

Dear Mr. Taylor:

Enclosed is Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") Integrity Management Rider ("IMR") Monthly Report for the month ending June 30, 2020.

Paragraph 7 of Piedmont's Service Schedule 317 requires monthly IMR reports to be filed within 45 days after the end of the month for which the report is being filed. This filing consists of various schedules constituting Piedmont's IMR monthly report for the month ended June 30, 2020.

This material is also being filed today by way of email to the Tennessee Public Utility Commission docket manager, Ectory Lawless. Please file the original of each and provide us a "filed" stamped copy of each via email to denise.guye@wallerlaw.com.

Very truly yours,

Paul S. Davidson

Paul S. Davidson

Enclosures

cc: Bruce Barkley
Pia Powers
Michelle Mairs
Alex Bradley
Daniel Whitaker
James Jeffries

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 1

Cumulative Integrity Management Investment Amount
Actual Integrity Management Investment, by Integrity Project Type

Line No.		Current Vintage Year: Vintage Year 8			All Vintage Years
		June 2020 Capital Expenditure [1]	Prior Cumulative Capital Expenditure [2]	Cumulative Capital Expenditure as of June 2020 [3]	Cumulative Capital Expenditure as of June 2020 [6]
	TN Direct				
1	Corrosion Control	$ 2,550.39	$ 580,724.07	$ 583,274.46	$ 8,524,997.89
2	Casing Remediation	$ 30,279.87	$ 2,364.26	$ 32,644.13	$ 909,918.98
3	Distribution Integrity	$ 2,927,552.14	$ 8,172,953.59	$ 11,100,505.73	$ 97,015,820.41
4	Transmission Integrity	$ 5,873,412.57	$ 25,262,897.49	$ 31,136,310.06	$ 242,407,549.42
5	Total	$ 8,833,794.97	$ 34,018,939.41	$ 42,852,734.38	$ 348,858,286.70
	Joint Property: CO3-State				
6	OASIS Project (Work & Asset Management System)	$ -	$ -	$ -	$ 133,880,060.70
7	TN % of CO-3 for Current Month [4]	15.65%			
8	Total Allocated to TN	$ -	$ -	$ -	$ 23,535,435.31
9	Total Capital Expenditures [Line 5 + Line 8]	$ 8,833,794.97	$ 34,018,939.41	$ 42,852,734.38	$ 372,393,722.01
10	Less: Amount Included in the Attrition Period [5]	$ -	$ -	$ -	$ 32,900,000.00
11	**Total Integrity Management Investment**	**$ 8,833,794.97**	**$ 34,018,939.41**	**$ 42,852,734.38**	**$ 339,493,722.01**

1/ Represents, for the current month, the actual Integrity Management Investment that is subject to this Rider

2/ Represents, as of the prior month, the cumulative Integrity Management Investment for the current Vintage Year that is subject to this Rider; this amount is shown in the prior month's report

3/ Represents, for the current Vintage Year through the current month, the cumulative Integrity Management Investment that is subject to this Rider

4/ Represents the TN% of Total Company Gas Plant Excluding Joint Property , which is updated annually

5/ Amount being recovered in existing base rates, per the Relevant Rate Order in Docket 11-00144

6/ Represents, for all Vintage Years through the current month, the cumulative Integrity Management Investment that is subject to this Rider. The cumulative Integrity Management Investment for Vintage Years 1, 2, 3, 4, 5, 6 and 7 which captures amounts through 10/31/19, is $296,640,987.63 ($100,306,282.52 for Vintage Year 1, $53,974,676.19 for Vintage Year 2, $18,441,896.09 for Vintage Year 3, $20,076,717.97 for Vintage Year 4, $38,244,253.18 for Vintage 5, $27,564,238.09 for Vintage Year 6 and $38,032,923.59 for Vintage Year 7).

Piedmont Natural Gas Company, Inc.
Integrity Management Rider
State of Tennessee

Schedule 2

Detail of Current Month's Integrity Management Investment Amount
Actual Capital Investment for Current Month, by Capital Funding Project

Line No.	Capital Project Type	Funding Project Number	District	Funding Project Description	June 2020
1	CORR-Corrosion Control	F0228798	17	Hillsboro Rd. Rectifier&Ground Bed	106.83
2	CORR-Corrosion Control	F0229704	17	Nashville Rectifier & Ground Bed	1,623.08
3	CORR-Corrosion Control	FP1708010	17	Nashville Anodes	689.83
4	CORR-Corrosion Control	FP1734186	17	Nashville New Rectifier & Ground B	130.65
5	CSNG-Casing & Remediation	F0231471	17	44th Ave N @ I-40 - 8" Pipe	30,279.87
6	DIMP-Distribution Integrity	F0215066	17	Maplewood Rd Valve	(550.54)
7	DIMP-Distribution Integrity	F0221329	17	10th Ave N Valve Replacement	(1,355.19)
8	DIMP-Distribution Integrity	F0221354	17	Davidson Drive @ Charlotte Pike Valve	329.67
9	DIMP-Distribution Integrity	F0222120	17	31st Ave @ West end Valve Replacement	6,483.12
10	DIMP-Distribution Integrity	F0222727	17	Brick Church Pike to West Trinity	1,554.88
11	DIMP-Distribution Integrity	F0222865	17	Post Place Retirement and pressure	155,464.68
12	DIMP-Distribution Integrity	F0224311	17	Hermitage Pressure Downgrade	647,283.71
13	DIMP-Distribution Integrity	F0224331	17	Paragon Mills Road	7,420.31
14	DIMP-Distribution Integrity	F0224337	17	Van Buren Renewel	95,855.10
15	DIMP-Distribution Integrity	F0224345	17	4934 Whites Creek Pk	216,915.93
16	DIMP-Distribution Integrity	F0224357	17	Patton Ave	22,130.00
17	DIMP-Distribution Integrity	F0225445	17	22nd Ave N @ Murphy Valve Replaceme	10,249.72
18	DIMP-Distribution Integrity	F0225698	17	Centennial Blvd Main Replacement	3,029.07
19	DIMP-Distribution Integrity	F0225705	17	Old Harding Pike Insulator	(8,800.74)
20	DIMP-Distribution Integrity	F0225786	17	Woodcrest Leak Repair	(9,300.29)
21	DIMP-Distribution Integrity	F0226414	17	Line 304 Convert to Dist (Station)	67,682.09
22	DIMP-Distribution Integrity	F0229092	17	39th Ave North	823.49
23	DIMP-Distribution Integrity	F0229495	17	1st ave south 12" 175# Replacement	64,114.11
24	DIMP-Distribution Integrity	F0230666	17	Old Lebanon Dirt Road Main Replacem	108,413.06
25	DIMP-Distribution Integrity	F0230684	17	Bordeaux Bridge Expainsion Joint -	3,745.88
26	DIMP-Distribution Integrity	F0231296	17	Ed Temple Blvd DIMP	656,541.80
27	DIMP-Distribution Integrity	F0231383	17	28th Ave N	52,758.44
28	DIMP-Distribution Integrity	F0231458	17	Charlotte Ave Casing Retirement	54,930.02
29	DIMP-Distribution Integrity	FP1734427	17	Grinstead Place	(1,518.08)
30	DIMP-Distribution Integrity	FP1734428	17	Broadmoor Drive	20,871.49
31	DIMP-Distribution Integrity	FP1734695	17	Spence Lane	699,627.36
32	DIMP-Distribution Integrity	FP1734726	17	Cowan St HP Distribution Pipeline	52,853.05
33	TIMP-Transmission Integrity	F0230575	17	Line 384 - Valve Automation - Stati	842.74
34	TIMP-Transmission Integrity	F0231014	17	ILI anomaly excavations on Line 307	288.41
35	TIMP-Transmission Integrity	F0231279	17	Level 1 dig repair on Line 308 imme	2,878.75
36	TIMP-Transmission Integrity	F0231370	17	Line 320 ILI Retrofit	453,072.18
37	TIMP-Transmission Integrity	FP1733398	17	South Nashville 20"	(1,066,389.16)
38	TIMP-Transmission Integrity	FP1734120	17	Line 431 Replacement	28,887.55
39	TIMP-Transmission Integrity	FP1734142	17	Line 308 Replacement	57,314.46
40	TIMP-Transmission Integrity	FP1734394	17	Line 431 Ph II Land	6,396,517.64
41	**Total (unallocated)**				**$ 8,833,794.97**
	subtotal: TN Direct (unallocated)				*$ 8,833,794.97*
	subtotal: CO-3 (unallocated)				*$ -*
					$ 8,833,794.97

Piedmont Natural Gas Company, Inc. Schedule 3
Integrity Management Rider
State of Tennessee

Schedule Detailing the Integrity Management Deferred Account Adjustment Recorded for the Month
Calculation of the IM Deferred Account Balance
Amount Due From (To) Customers per GL Account No. 0253139

Line No.			Jun-20
1	Beginning Balance	*Prior Month's IMR Report*	$ (8,453,028.63)
2	IMR Revenue Recognition	*Prior Annual IMR Report*	1,008,663.86
3	(Collections from IM Adjustment)	*see Separate Schedule*	(799,053.31)
4	Ending Balance Before Interest	*sum Lines 1 thru 3*	(8,243,418.08)
5	Average Balance	*(Line 1 + Line 4) /2*	(8,348,223.36)
6	Accrued Interest	*Line 5 * Line 9*	(33,042.27)
7	Ending Balance After Interest	*Line 4 + Line 6*	$ (8,276,460.35)
8	Applicable Annual Interest Rate	*same as for ACA*	0.047500
9	Monthly Interest Rate	*Line 8 / 12*	0.003958
10	Actual GL #0253139 EOM Balance	*per GL*	$ (8,276,460.35)
11	Variance	*Line 7 - Line 10*	$ -

Journal Entry: To Record Revenue	
47136 0253139 GA489 PTOP	1,008,663.86
47136 0480000 GA489 PTOP 0526 RESVAL	(601,607.47)
47136 0481200 GA489 PTOP 0526 COMSTD	(314,703.11)
47136 0481000 GA489 PTOP 0526 INDSLS	(13,606.88)
47136 0483011 GA489 PTOP 0526 GASRSL	(282.43)
47136 0489000 GA489 PTOP 0526 BOTHRV	(78,463.97)

Journal Entry: To Record Interest	
47136 0253139 GA626 PTOP	(33,042.27)
47136 0431150 GA626 PTOP 0526	33,042.27

Piedmont Natural Gas Company, Inc. Schedule 4
Integrity Management Rider
State of Tennessee

General Ledger Support
Integrity Management Deferred Account Adjustment Recorded for the Month

Calculation of the IM Adjustment Collections:

		Jun-20				
		IM Adjustment ($ per therm)	x	Usage (therms)	=	Collections ($)
Line No.						
1	Residential (301)	0.11730		3,418,963		401,044.36
2	Small General Sales (302)	0.10247		1,757,704		180,111.93
3	Medium General Sales (352)	0.10247		725,368		74,328.46
4	Experimental Motor Vehicle Fuel (343/302/352)	0.10247		16,853		1,726.93
5	Firm Lg General Sales (303)	0.04551		277,261		12,618.15
6	Experimental Motor Vehicle Fuel (343/303)	0.04551		906		41.23
7	Firm Lg General Transportation (313)	0.04551		1,068,087		48,608.65
8	Experimental Motor Vehicle Fuel (343/313)	0.04551		124,256		5,654.89
9	Firm Resale (310)	0.04551		1,026		46.69
10	Interruptible Lg General Sales (304)	0.01138		17,855		203.19
11	Interruptible Lg General Transportation (314)	0.01138		6,561,409		74,668.83
12	**Total**					**$ 799,053.31**

Journal Entry: To Record Collections

47136 0480000 GA489 PTOP 0526 RESVAL	401,044.36
47136 0481200 GA489 PTOP 0526 COMSTD	180,111.93
47136 0481200 GA489 PTOP 0526 COMSTD	76,055.39
47136 0481000 GA489 PTOP 0526 INDSLS	12,659.38
47136 0489000 GA489 PTOP 0526 BOTHRV	54,263.54
47136 0483011 GA489 PTOP 0526 GASRSL	46.69
47136 0481000 GA489 PTOP 0526 INDSLS	203.19
47136 0489000 GA489 PTOP 0526 BOTHRV	74,668.83
47136 0253139 GA489 PTOP	(799,053.31)
	-

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
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1-25. Refer to the "June 2020 Billing Rates" tab of the "1_Sales and Transportation Pro Forma Revenue -CONFIDENTIAL" spreadsheet included with the Company's filing.

RESPONSE: DR 1-25 does not request any information.

Name and Title of Preparer: Kally Couzens, Manager - Rates and Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-26. Provide the source and support for the "Integrity Management Adjustment – Rev Requirement Component" amounts included in Column S as hard-coded numbers.

RESPONSE: See the attachment with the source and support for the IMR Revenue Requirement rate component. The rates and amounts reflected in the attachment are from Piedmont's filed annual IMR report in Docket No. 19-00107, which was approved by the TPUC by Order dated 6/29/20.

Name and Title of Preparer: Kally Couzens, Manager - Rates and Regulatory Strategy

Name and Title of Responsible Person: Kally Couzens, Manager - Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
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1-27. Refer to the "June 2020 Billing Rates" tab of the "1_Sales and Transportation Pro Forma Revenue -CONFIDENTIAL" spreadsheet included with the Company's filing. Provide a copy of the monthly billing rates for each month of the test period (April 2019 – March 2020) in this same format.

RESPONSE: The versions of Tariff Sheet No. 1 in effect during each month of the Test Period are as follows:

- 04-2019: Fifty-Ninth Revised Sheet No.1 (eff. beginning November 2018)
- 05-2019: Sixtieth Revised Sheet No.1 (eff. beginning May 2019)
- 06-2019: Sixty-First Revised Sheet No.1 (eff. beginning June 2019)
- 07-2019: Sixty-First Revised Sheet No.1 (eff. beginning June 2019)
- 08-2019: Sixty-First Revised Sheet No.1 (eff. beginning June 2019)
- 09-2019: Sixty-First Revised Sheet No.1 (eff. beginning June 2019)
- 10-2019: Sixty-First Revised Sheet No.1 (eff. beginning June 2019)
- 11-2019: Sixty-Second Revised Sheet No.1 (eff. beginning November 2019)
- 12-2019: Sixty-Second Revised Sheet No.1 (eff. beginning November 2019)
- 01-2020: Sixty-Second Revised Sheet No.1 (eff. beginning November 2019)
- 02-2020: Sixty-Second Revised Sheet No.1 (eff. beginning November 2019)
- 03-2020: Sixty-Third Revised Sheet No.1 (eff. beginning March 2020)

Please see the attachment for each of these versions of Tariff Sheet No. 1.

PIEDMONT NATURAL GAS COMPANY, INC.
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Name and Title of Preparer: Cassandra Ramsey, Senior Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Kally Couzens, Manager - Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-28. Refer to the "Normal vs. Special" tab of the "MFR 51 Attachment" spreadsheet included with the Company's response to MFR 51 that provides the monthly plant additions split between normal additions and special project additions from January 2017 through March 2020. Provide this same monthly information from May 2011 (the end of the last rate case in Docket 11-00144) through December 2016.

RESPONSE: See the Company's response to Request No. 4(b) for additions by category. Special projects were defined as all those categorized as Government Relocation, Government Reimbursable, System Infrastructure, New Services, New Business and Purchased Meters, ERTS and Regulators.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-29. Refer to the "Normal vs. Special" tab of the "MFR 51 Attachment" spreadsheet included with the Company's response to MFR 51 that provides the monthly plant additions split between normal additions and special project additions from January 2017 through March 2020. Provide the source and support for the monthly amounts contained on this spreadsheet by subaccount.

RESPONSE: See the 4 attachments. The source of this information is Power Plan, Piedmont's asset accounting system of record. The special projects are those categorized as Government Relocation, Government Reimbursable, System Infrastructure, New Services, New Business and Purchased Meters, ERTS and Regulators.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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Date Issued: August 17, 2020
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1-30. Refer to the "Additions and Retirements" tab of the "MFR 51 Attachment" spreadsheet included with the Company's response to MFR 51 that provides the monthly plant additions and retirements from January 2017 through March 2020. Provide this same monthly information from May 2011 (the end of the last rate case in Docket 11-00144) through December 2016.

RESPONSE: The source of the information provided in the Company's response to MFR Item 51 is Piedmont's asset accounting system, PowerPlan. PowerPlan is Piedmont's system of record for all capital assets. The information provided in MFR Item 51 was obtained from the monthly plant in service rollforward report, which is a PowerPlan system generated report. The monthly plant in service rollforward report is provided in the Company's response to Request No. 3 of this data request.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-31. Refer to the "Additions and Retirements" tab of the "MFR 51 Attachment" spreadsheet included with the Company's response to MFR 51 that provides the monthly plant additions and retirements from January 2017 through March 2020. Provide the source and support for the monthly amounts contained on this spreadsheet by subaccount.

RESPONSE: The source of the information provided in the Company's response to MFR item 51 is Piedmont's asset accounting system, PowerPlan. PowerPlan is Piedmont's system of record for all capital assets. The information provided in MFR item 51 was obtained from the monthly plant in service rollforward report, which is a PowerPlan system generated report. The monthly plant in service rollforward report is provided in the Company's response to Request No. 3 of this data request.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-32. Refer to the "CIAC" tab of the "MFR 51 Attachment" spreadsheet included with the Company's response to MFR 51 that provides the annual contributions in aid of construction from January 2017 through March 2020. Provide this same annual information from 2011 (the end of the last rate case in Docket 11-00144) through December 2016.

RESPONSE: Please see the Company's response to Request No. 39.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-33. Refer to the spreadsheet attachment provided with the Company's response to MFR 52 that provides the forecasted plant additions by month from April 2020 through December 2021 for both Tennessee plant and joint plant. Provide the source and support by month for the plant additions contained in this spreadsheet.

RESPONSE: The information provided in the Company's response to MFR item 52 came from a query of Piedmont's asset accounting system of record, PowerPlan. Capital budget details are entered into PowerPlan once approved as part of the capital budgeting process, and then updated in PowerPlan as plans change. Project details such as expenditures by plant utility account, project number, project name, project description, project category and estimated project in service date are all entered into PowerPlan such that queries, such as the one used for MFR item 52, can be run to extract this data.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-34. Refer to the spreadsheet attachment provided with the Company's response to MFR 52 that provides the forecasted plant additions by month from April 2020 through December 2021 for both Tennessee plant and joint plant. In addition, refer to the Company's response to MFR 53 that requested a copy of the authorization for the attrition year construction projects. The Company's response to MFR 53 indicates that there "...are no paper signed authorizations for any projects." However, in order to consider these attrition year construction projects within the rate case, the Consumer Advocate needs to confirm that these construction projects have by the Company's management. Therefore, provide an attestation from the Company's Chief Executive Officer and Chief Financial Officer that the need for the construction projects included in MFR 52 have been reviewed and the financing has been reserved for their construction.

RESPONSE: Duke Energy has a system of financial internal controls that management, including the CEO and CFO, must attest to as defined in the SEC rules. The entity level controls at Duke Energy include a Capitalization Policy and the appropriate review for approval of capital projects. See Duke Energy's 10-k filing at the following link for the CEO and CFO attestation in Item 9A (page 244): https://www.duke-energy.com/_/media/pdfs/our-company/investors/2019-duke-energy-form-10-k.pdf?la=en

Also included in the 10-k is the external auditor's opinion on internal control over financial reporting that Duke Energy maintained effective internal controls during the most recent fiscal year.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Reem Grammatico, Director - Corporate Accounting

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

ATTESTATION

Steven K. Young, being duly sworn, deposes and says that he is Chief Financial Officer of Duke Energy Corporation, and in that capacity hereby attests that the budgeted construction projects identified in Piedmont Natural Gas Company, Inc.'s response to MFR No. 52 in Tennessee Public Utility Commission Docket No. 20-00086 are necessary for Piedmont to continue to provide safe and reliable service to customers served by Piedmont in Tennessee, that such projects are planned, have been budgeted, and funds for their completion have been reserved and will be made available to Piedmont to complete such projects.

Steven K. Young

Steven K. Young
Executive Vice President and CFO

Mecklenburg County, North Carolina
Signed and sworn to before me this day by Steven K. Young

Date: 9/9/20

Amy E. Lungy

Notary Public

(Official Seal)

My commission expires: 11/16/22

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

ATTESTATION

Lynn J. Good, being duly sworn, deposes and says that she is Chief Executive Officer of Duke Energy Corporation, and in that capacity hereby attests that the budgeted construction projects identified in Piedmont Natural Gas Company, Inc.'s response to MFR No. 52 in Tennessee Public Utility Commission Docket No. 20-00086 are necessary for Piedmont to continue to provide safe and reliable service to customers served by Piedmont in Tennessee, that such projects are planned, have been budgeted, and funds for their completion have been reserved and will be made available to Piedmont to complete such projects.

Lynn J. Good
Chairman, President and CEO

Mecklenburg County, North Carolina
Signed and sworn to before me this day by Lynn J. Good

Date: 9/9/20

Notary Public

(Official Seal)

My commission expires: 11/16/22

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
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1-35. Provide a copy of the Company's construction budgets and actual construction expenditures for both Tennessee and joint plant by year from 2011 through 2019.

RESPONSE: See attachment. Budgeted and reported actuals are compared by management at a Total Piedmont level, not at a state jurisdictional level for Piedmont. IMR capital expenditures were tracked separately in the report. These reports were reviewed at monthly financial meetings with gas leadership.

Name and Title of Preparer: John Robson, Director - Gas FPA

Name and Title of Responsible Person: Joel Rutledge, Director - Finance Gas Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-36. Refer to the Company's response to MFR58 regarding common plant that is allocated to Nashville. The Company's response indicates that no plant is allocated to Tennessee, but instead a portion of the return on Duke Energy Business Service assets (PPE, Pension and Inventory) as well as a portion of depreciation expense is charged to Tennessee. Provide the following information related allocation:

a. Provide the monthly investment and accumulated depreciation by subaccount on total common plant (PPE, Pension and Inventory) that is allocated to Tennessee by month from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

b. Provide the monthly depreciation expense by subaccount on total common plant (PPE, Pension and Inventory) that is allocated to Tennessee by month from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

c. Provide a monthly reconciliation between the depreciation expense on joint plant actually charged to Tennessee and the depreciation expense calculated on common plant (PPE, Pension and Inventory) that is allocated to Tennessee by month from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

d. Provide the source and support for the depreciation rates used to calculate depreciation expense that is allocated to Tennessee on total common plant (PPE, Pension and Inventory).

e. Provide a copy of all commission orders in Tennessee, North Carolina and South Carolina approving the Company's current depreciation rates on Duke Energy

Business Service assets (PPE, Pension and Inventory) that are allocated to different states.

f. Provide the source and support for the Tennessee allocation factors used to allocate depreciation expense and return on Duke Energy Business Service common assets (PPE, Pension and Inventory) by month from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020.

RESPONSE: Piedmont was acquired by Duke Energy Corporation in October 2016. There was no activity of this nature recorded on Piedmont's books prior to January 1, 2017. Information is provided for January 2017 - March 2020. See attachment for the Company's responses to the individual subparts of this request.

Name and Title of Preparer: Jeff Masucci, Senior Financial Analyst

Name and Title of Responsible Person: Jeff Setser, Director - Allocations and Reporting

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-37. Provide the monthly accumulated depreciation balance (direct and allocated) by subaccount from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 detailing the beginning monthly balance, accrual, retirements, cost of removal, salvage, other adjustments and the ending balance in Excel format with all formulas intact.

RESPONSE: See the 10 Excel attachments. Please note that TN Allocation percentage is updated after each fiscal year-end. Prior to November 2016, Piedmont's fiscal year ended each October 31. Piedmont had a 2-month stub fiscal year from November 2016 to December 2016. Starting in January 2017, Piedmont aligned its fiscal year with the calendar year so as to end each December 31.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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Date Issued: August 17, 2020
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1-38. Provide the monthly balance in Customer Deposits and Accrued Interest on Customer Deposits by subaccount from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 detailing the beginning monthly balance, additions, removals, adjustments and ending monthly balance in Excel format with all formulas intact.

RESPONSE: Please see CAD DR 1-38 attachment 1 of 3 for the Customer Deposit account activity from May 2011 - March 2020. Please see CAD DR 1-38 attachment 2 of 3 for a listing of customer deposits by customer account as of August 28, 2020. This information is only available as of a current point in time. Please see CAD DR 1-38 attachment 3 of 3 for the Accrued Interest on Customer Deposit account activity from May 2011 - March 2020. The monthly account balances for both of these accounts from May 2011 - March 2020 is provided in response to CAD DR 1-45.

Name and Title of Preparer: Nicole Aquilina, Manager Accounting II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utilities & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-39. Provide the monthly balance in Contributions in Aid of Construction and Customer Advances by subaccount from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 detailing the beginning monthly balance, additions, removals, adjustments and ending monthly balance in Excel format with all formulas intact.

RESPONSE: See the attachment for the general ledger detail from May 2011 through March 2020. Piedmont's general ledger system does not differentiate between additions, removals and adjustments.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-40. Provide the monthly balance in Construction Work in Progress by subaccount from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 detailing the beginning monthly balance, expenditures, closures, adjustments and ending monthly balance in Excel format with all formulas intact.

RESPONSE: See attachment. The rollforward report in the attachment is for Account 0107000 and is provided on an annual basis due to system constraints with querying historical CWIP information.

Name and Title of Preparer: Elena Gogea, Senior Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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Date Due: September 8, 2020

1-41. Provide the monthly balance in Gas Inventory by subaccount (volumes and cost) from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 detailing the beginning monthly balance, injections, withdrawals, boil-off, adjustments, ending monthly balance and unit price calculation in Excel format with all formulas intact.

RESPONSE: Please see the two attachments. Please note that the withdrawals on Attachment 1 represent total withdrawals and includes withdrawals, boil-off and adjustments. Attachment 2 breaks down the withdrawals into the various categories.

Name and Title of Preparer: Susan Whitley, Lead Analyst

Name and Title of Responsible Person: MaryBeth Tomlinson, Manager - Gas Accounting

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-42. Provide a list of all deferrals the Company presently has recorded on its books, the account number the deferral is recorded in, the annual amount of amortization related to each deferral, the amount of each deferral that is included in the current rate case, and the Commission docket number allowing the recording and/or amortization of the deferral.

RESPONSE: See attachment.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
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Date Due: September 8, 2020

1-43. Refer to the "Summary Worksheet" tab of the "5B_DefRate Case Adj - CONFIDENTIAL" spreadsheet included with the Company's response to MFR 12 that provides the estimated total rate case expenses for the current docket. Provide the source and support for each estimated cost on this spreadsheet.

RESPONSE: Please see the attachment for Piedmont expenses calculation. Piedmont requested each consultant to provide an estimate of total rate case expenses (assuming the parties settle prior to the evidentiary hearing). There is no further breakdown of detail from consultants.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

Brian S. Heslin
Deputy General Counsel

Duke Energy Corporation
550 South Tryon St (DEC 45A)
Charlotte, NC 28202

980.373.0550
Brian.Heslin@duke-energy.com

January 16, 2020

Via Email

Mr. Dane A. Watson, PE, CDP
Managing Partner
Alliance Consulting Group
101 E. Park Blvd., Suite 220
Plano, TX 75074

Subject: Piedmont Natural Gas Rate Case in Tennessee

Dear Mr. Watson:

The purpose of this Engagement Letter ("Engagement") is to retain your services as an expert on behalf of Piedmont Natural Gas (the "Company") in the 2020 rate case in Tennessee ("Rate Case"). The terms of the proposal under this Engagement are as follows:

1. The Company, through its Office of General Counsel, is retaining Dane A. Watson ("Mr. Watson") of Alliance Consulting Group to serve as a consulting expert and witness regarding the Rate Case. The fees and other amounts charged by Mr. Watson with respect to the Rate Case under this Engagement shall be the responsibility of the Company.

2. Mr. Watson will initially provide the Company with a depreciation study and a first draft of testimony estimated at $39,500. Upon the filing of any pre-filed testimony, Mr. Watson will be considered a testifying expert. As a testifying expert, Mr. Watson will make himself reasonably available to testify on behalf of the Company in depositions, hearings, trials and other proceedings as the Company may require in connection with this Rate Case, and Mr. Watson and his staff may also be required to perform other related services such as responding to data and discovery requests.

3. Mr. Watson agrees to perform services as directed by Brian S. Heslin ("Mr. Heslin") or another attorney within the Office of General Counsel of the Company, or by the Company's outside counsel, including, but not limited to:

a. preparing a depreciation study on Tennessee assets;

b. preparing an initial draft of written testimony;

c. responding to data requests;

d. defending his testimony as required;

e. evaluating intervener testimony and preparing and defending rebuttal testimony; and

f. providing other assistance in connection with the Rate Case within the scope of his area of expertise as requested by the Company's Office of General Counsel or its outside counsel.

Mr. Watson agrees to provide services in a professional and timely manner, recognizing that Commission deadlines are involved and that time is of the essence. Mr. Watson will be kept apprised of deadlines and given as much advance notice as practicable in order to facilitate scheduling and minimize conflicts.

4. The Company will pay Mr. Watson at the hourly rates noted in Attachment A for time spent on the Rate Case and the aforementioned services under this Engagement. The Company will also reimburse the direct, out-of-pocket expenses Mr. Watson incurs in the course of performing services in connection with the Rate Case under this Engagement. This includes estimated travel expenses for interviews, copy charges, research costs, and long-distance telephone charges. This also includes the PowerPlant royalty pass through of $1,082.50, up to an annual total of $2,706.25. In addition, the Company will provide offices and facilities for necessary staff during the Rate Case under this Engagement.

5. As a testifying expert, Mr. Watson understands that documents he sends, receives, and generates may become discoverable in litigation, including drafts and notes prepared prior to the time that his opinion, report or pre-filed testimony is finalized. Mr. Watson therefore agrees to preserve any written materials (including emails) that are sent, received, or generated in connection with the Rate Case under this Engagement.

6. Mr. Watson acknowledges and agrees that all information (whether printed, electronic, oral, or otherwise) that he and his staff send, generate, and receive in the course of this Engagement shall be confidential, and shall not be disclosed to any third party without the express consent of the Company's Office of General Counsel or its outside counsel. Mr. Watson and his staff will use such confidential information solely in connection with this Engagement, and for no other purpose. In addition, Mr. Watson and his staff will keep the fact of their retention in this Engagement confidential until he is formerly designated as a testifying expert or the Company's Office of General Counsel or its outside counsel otherwise authorize him to disclose the fact that he has been retained.

7. Mr. Watson may also be receiving certain confidential documents produced in discovery in the Rate Case. If a protective order is entered governing the use of such documents, Mr. Watson agrees that he will abide by its terms.

8. The Company may terminate this Engagement at any time by providing Mr. Watson with written notice of termination, in which event he will be paid for amounts owed through the date of termination. Because of the importance of Mr. Watson's service to the Company in relation to the Rate Case, if he is designated as a testifying expert, he may terminate this Engagement only for good cause, after giving the Company at least thirty (30) days prior

written notice of such cause and the opportunity to cure any default that may exist. The confidentiality provisions of this Engagement survive any termination hereof.

To accept the proposal under this Engagement, please execute where indicated below and email a scan to me. Please do not hesitate to contact me if you have any questions or if there are any further issues we need to discuss.

Again, I look forward to working with you.

Sincerely,

Brian S. Heslin

AGREED AND ACCEPTED:

Dane A. Watson

Mr. Dane A. Watson, PE, CDP
Managing Partner
Alliance Consulting Group

ATTACHMENT A
ALLIANCE CONSULTING GROUP
HOURLY BILLING RATES

INDIVIDUAL	HOURLY RATE
Partner	$270
Senior Consultant	$195
Analyst	$70

Brian S. Heslin
Deputy General Counsel

Duke Energy Corporation
550 South Tryon St (DEC 45A)
Charlotte, NC 28202

980.373.0550
Brian.Heslin@duke-energy.com

January 7, 2020

Via Email

Mr. Michael Morganti
Principal
Management Applications Consulting Inc.
1103 Rocky Drive, Suite 201
Reading, PA 19609

Subject: Piedmont Natural Gas 2020 Rate Case in Tennessee

Dear Mr. Morganti:

The purpose of this Engagement Letter ("Engagement") is to present a proposal pursuant to which you will serve as an expert on behalf of Piedmont Natural Gas (the "Company") in the 2020 rate case in Tennessee ("Rate Case"). The terms of the proposal under this Engagement are as follows:

1. The Company, through its Office of General Counsel, is retaining Management Applications Consulting, Inc. ("MAC") to serve as consulting experts and witnesses regarding the Rate Case. The fees and other amounts charged by you with respect to this Engagement shall be the responsibility of the Company.

2. You will initially provide us with a study of cash working capital (aka a lead-lag study) and a cost of service study. Paul M. Normand ("Mr. Normand") will serve as the expert filing testimony. As a testifying expert, Mr. Normand will be reasonably available to testify on behalf of the Company in depositions, hearings, trials and other proceedings as we may require in connection with this Rate Case. Mr. Normand and MAC staff may also be required to perform other related services such as responding to data and discovery requests.

3. You agree to perform services as directed by me or another attorney within the Office of General Counsel of the Company, or by the Company's outside counsel, including, but not limited to:

a. preparing a study of cash working capital (aka a lead-lag study);

b. preparing a class cost of service study;

c. responding to data requests;

d. defending your testimony as required;

e. evaluating intervener testimony and preparing and defending rebuttal testimony; and

f. providing other assistance in connection with the Rate Case within the scope of your area of expertise.

You agree to provide services in a professional and timely manner, recognizing that Commission deadlines are involved and that time is of the essence. We will keep you apprised of deadlines and give you as much advance notice as practicable in order to facilitate scheduling and minimize conflicts.

4. The Company will pay you at the hourly rates noted in Attachment A for time spent on the Rate Case and the aforementioned services under this Engagement. The Company will also reimburse the direct, out-of-pocket expenses you incur in the course of performing services in connection with the Rate Case under this Engagement, such as out-of-town travel expenses, copy charges, research costs, and long-distance telephone charges. In addition, the Company will provide offices and facilities for necessary MAC staff during the Rate Case under this Engagement.

5. As a testifying expert, it is understood that documents you send, receive, and generate may become discoverable in litigation, including drafts and notes prepared prior to the time that your opinion, report or pre-filed testimony is finalized. You therefore agree to preserve any written materials (including emails) that are sent, received, or generated in connection with the Rate Case under this Engagement.

6. You acknowledge and agree that all information (whether printed, electronic, oral, or otherwise) that you and MAC staff send, generate, and receive in the course of this Engagement shall be confidential, and shall not be disclosed to any third party without the express consent of the Company's Office of General Counsel or its outside counsel. You and MAC staff will use such confidential information solely in connection with this Engagement, and for no other purpose. In addition, you and MAC staff will keep the fact of your retention in this Engagement confidential until you are formerly designated as a testifying expert or the Company's Office of General Counsel or its outside counsel otherwise authorize you to disclose the fact that you have been retained.

7. You may also be receiving certain confidential documents produced in discovery in the Rate Case. If a protective order is entered governing the use of such documents, you and MAC staff will abide by its terms.

8. The Company may terminate this Engagement at any time by providing you with written notice of termination, in which event you will be paid for amounts owed through the date of termination. Because of the importance of your services to the Company in relation to the Rate Case, if you are designated as a testifying expert, you may terminate this Engagement only for good cause, after giving the Company at least thirty (30) days prior written notice of such cause

and the opportunity to cure any default that may exist. The confidentiality provisions of this Engagement survive any termination hereof.

To accept this proposal, please execute this Engagement where indicated below and email a scan to me. Please do not hesitate to contact me if you have any questions or if there are any further issues we need to discuss.

Again, I look forward to working with you.

Sincerely,

Brian S. Heslin

AGREED AND ACCEPTED:

Mr. Michael Morganti
Principal
Management Applications Consulting Inc.

ATTACHMENT A
MANAGEMENT APPLICATIONS CONSULTING INC.
HOURLY BILLING RATES

INDIVIDUAL	HOURLY RATE
Managing Consultant	$250
Senior Consultant	$225
Consultant	$150
Analyst	$125
Junior Analyst	$100
Technical Assistant	$75
Word Processing	$50

Matter Assignment

Pursuant to Outside Counsel Services Agreement Dated January 22, 2018

Date: March 3, 2020

To: James H. Jeffries IV
Firm: McGuireWoods LLP
Address: 201 North Tryon Street
Suite 3000
Charlotte, NC 28202-2146
Email: jjeffries@mcguirewoods.com
Phone: (704) 343-2348

Subject: Matter Assignments: Piedmont – 2020 TN Rate Case (CAP)
Duke Energy Matter Reference No.: 2020-0109

The Firm is retained to represent Duke Energy Corporation's interest and render advice with respect to the following:

Scope of Services: To represent Piedmont Natural Gas Company, Inc.'s interest and render legal support with respect to the Tennessee rate case.

Modifications to the terms and conditions of Outside Counsel Engagement Agreement (if any): None.

Duke Energy Attorney:

Brian S. Heslin
Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street (DEC45A)
Charlotte, NC 28202
Email: brian.heslin@duke-energy.com
Phone: (980) 373-0550
Fax: (980) 373-8534

Signature: _____

Agreed to and accepted by:

McGuireWoods LLP (the "Firm")

By: _____ (the "Firm Attorney")
James H. Jeffries IV

Date: March 3, 2020

Brian S. Heslin
Deputy General Counsel

Duke Energy Corporation
550 South Tryon St (DEC 45A)
Charlotte, NC 28202

980.373.0550
Brian.Heslin@duke-energy.com

March 9, 2020

Via Email

Mr. Robert B. Hevert
ScottMadden, Inc.
1900 West Park Drive, Suite 250
Westborough, MA 01581

Subject: Piedmont Natural Gas 2020 Tennessee Rate Case

Dear Mr. Hevert:

The purpose of this Engagement Letter ("Engagement") is to retain your services as an expert on behalf of Piedmont Natural Gas (the "Company") in the 2020 rate case in Tennessee ("Rate Case"). The terms of the proposal under this Engagement are as follows:

1. The Company, through its Office of General Counsel, is retaining Robert B. Hevert ("Mr. Hevert") of ScottMadden, Inc. to serve as a consulting expert and possibly a testifying expert regarding the Rate Case. The fees and other amounts charged by Mr. Hevert with respect to the Rate Case under this Engagement shall be the responsibility of the Company.

2. Mr. Hevert will provide the Company with his opinion regarding the Company's cost of equity and direct issues, as well as his opinions on any additional issues which may be requested in the future. Mr. Hevert will provide for review draft written testimony regarding the Company's cost of equity proposed in the Rate Case at any stage of the Rate Case (direct, rebuttal, etc.). Upon the filing of pre-filed testimony, Mr. Hevert will be considered a testifying expert. As a testifying expert, he will be reasonably available to testify on behalf of the Company in depositions, hearings, trials and other proceedings as the Company may require in the Rate Case. Mr. Hevert and his staff may also be required to perform other related services such as responding to data and discovery requests.

3. Mr. Hevert agrees to perform services as directed by Brian S. Heslin ("Mr. Heslin") or another attorney within the Office of General Counsel of the Company, or by the Company's outside counsel, including, but not limited to:

a. preparing preliminary estimates of the Company's cost of equity and analyses regarding likely recommendations of opponents under previously provided methodology;

b. conducting an independent study of the cost of equity capital of the Company;

c. preparing written testimony on his cost of equity findings and return on equity recommendation;

d. responding to data requests;

e. defending his testimony as required;

f. evaluating intervener testimony and preparing and defending rebuttal testimony; and

g. providing other assistance in the Rate Case within the scope of his area of expertise as requested by the Company's Office of General Counsel or its outside counsel.

Mr. Hevert agrees to provide services in a professional and timely manner, recognizing that Commission deadlines are involved and that time is of the essence. Mr. Hevert will be kept apprised of deadlines and given as much advance notice as practicable in order to facilitate scheduling and minimize conflicts.

4. The Company will pay Mr. Hevert at the hourly rates noted in Attachment A for time spent on the Rate Case and the aforementioned services under this Engagement. The Company will also reimburse the direct, out-of-pocket expenses Mr. Hevert incurs in the course of performing services in connection with the Rate Case under this Engagement, such as out-of-town travel expenses, copy charges, research costs, and long-distance telephone charges. In addition, the Company will provide offices and facilities for necessary staff during the Rate Case under this Engagement.

5. As a testifying expert, Mr. Hevert understands that documents sent, received, and generated may become discoverable in litigation, including drafts and notes prepared prior to the time that his opinion, report or pre-filed testimony is finalized. Mr. Hevert therefore agrees to preserve any written materials (including emails) that are sent, received, or generated in connection with the Rate Case under this Engagement.

6. Mr. Hevert acknowledges and agrees that all information (whether printed, electronic, oral, or otherwise) sent, generated, and received by him in the course of the Rate Case shall be confidential, and shall not be disclosed to any third party without the express consent of the Company's Office of General Counsel or its outside counsel. Mr. Hevert will use such confidential information solely in connection with the Rate Case, and for no other purpose. In addition, Mr. Hevert will keep the fact of his retention in this Engagement confidential until he is formerly designated as a testifying expert or the Company's Office of General Counsel or its outside counsel otherwise authorize him to disclose the fact that he has been retained.

7. Mr. Hevert may also be receiving certain confidential documents produced in discovery in the Rate Case. If a protective order is entered governing the use of such documents, Mr. Hevert agrees that he will abide by its terms. Notwithstanding anything contained in this Agreement to the contrary Mr. Hevert shall be allowed to retain one copy of deliverables to document the conduct of its work and its exercise of due professional care.

8. The Company may terminate this Engagement at any time by providing Mr. Hevert with written notice of termination, in which event he will be paid for amounts owed through the

date of termination. Because of the importance of Mr. Hevert's service to the Company in relation to the Rate Case, if he is designated as a testifying expert, he may terminate this Engagement only for good cause, after giving the Company at least thirty (30) days prior written notice of such cause and the opportunity to cure any default that may exist. The confidentiality provisions of this Engagement survive any termination hereof.

To accept the proposal under this Engagement, please execute where indicated below and email a scan to me. Please do not hesitate to contact me if you have any questions or if there are any further issues we need to discuss.

Again, I look forward to working with you.

Sincerely,

Brian S. Heslin

AGREED AND ACCEPTED:

Mr. Robert B. Hevert
ScottMadden, Inc.

ATTACHMENT A
SCOTTMADDEN, INC.
HOURLY BILLING RATES

INDIVIDUAL	HOURLY RATE
Partner	$470
Director	$365
Manager	$340
Senior Associate	$300
Director of Research	$300
Associate	$255
Benchmarking Manager	$255
Clean Tech Specialist	$230
Senior Analyst	$170
Survey Manager	$250
Survey Administration	$150
Analyst/Research Analyst	$145

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-44. Refer to the "5H_Uncollectibles Adj" spreadsheet included with the Company's response to MFR 12 that provides the uncollectible accounts data for the test period. Provide this same information and format by month for January 2017 through March 2020.

RESPONSE: See attachment for uncollectible information for net charge offs by month for January 2017 - March 2020.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
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1-45. Refer to the Company's response to MFR 56 regarding the average monthly balances for select accounts for 2019. Provide this same monthly information from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 in Excel format.

RESPONSE: See attachment.

Name and Title of Preparer: Nicole Aquilina, Manager - Accounting II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
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1-46. Describe in detail the Company's methodology for allocating Corporate and other operating expenses to Tennessee. Provide a calculation of any percentages used with underlying assumptions by year for 2017 to 2020.

RESPONSE: See the 8 attachments for the computation of the Composite Allocation Factors for each fiscal year and the Net Plant Factors for each fiscal year.

Income statement items (with certain exception, as discussed in the next paragraph) that cannot be directly assigned to a jurisdiction are charged to a 2-state (NC/SC) or 3-state (TN/NC/SC) business unit and then allocated using the Composite Allocation Factors for state jurisdictional regulatory reporting purposes. The Composite Allocation Factors are updated annually in January using direct labor percentages, gross plant percentages, and customer count percentages as of December labor and plant from the prior year and March customer counts from the prior year. In general, income statement items that are recorded to a 2-state Piedmont business unit are allocated using the 2-state Composite Allocation Factor, and income statement items that are recorded to a 3-state Piedmont business units are allocated using the 3-state Composite Allocation Factor.

Depreciation expense related to 3-state Piedmont joint property and 2-state Piedmont joint property are allocated using the Net Plant Factor, as the activity in those accounts is driven by plant, not the factors used in calculating the Composite Allocation Factor. The same goes for AFUDC and certain income tax expense accounts.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

Name and Title of Preparer: Doug Templeton - Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman - Director Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-47. Provide a detailed calculation with explanation for the 22 accounting and pro forma adjustments listed on Exhibit QPB-7, Pages 3 through 5. If these adjustments are already provided on workpapers submitted in response to MFR Item 12, then reference the appropriate Excel file and tab names.

RESPONSE: Please see the MFR 12 Index. The MFR 12 Index was emailed by Piedmont's counsel to the Consumer Advocate Division on August 3, 2020 pursuant to the Consumer Advocate's request.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-48. Provide a salary & wage and benefit price-out using wage rates at March 31, 2020 including payroll capitalized, for every Tennessee direct employee and every other employee that allocates a portion of their time to Tennessee.

RESPONSE: See attachment. Consistent with the response provided by the Company for MFR Item 31, the salary information provided in response to this request is for employees who direct charged their time to any Piedmont business unit during the test period, including those business units not subject to Tennessee allocation (North Carolina direct BUs, South Carolina Direct BUs and PNG 2-state BUs).

In addition to the benefit loader rate provided within the attachment, incentive compensation is also recorded as a percentage of labor. The incentive compensation rate for 2020 for all non-union employees is 10.5%, except for DEBS employees. The rate for DEBS employees is 11.5%. The rate for union employees is 3%.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-49. Provide the number of Tennessee direct employees and other allocated employees by year from 2011 (the end of the last rate case in Docket 11-00144) through 2019.

RESPONSE: See attachment for the total number of employees reported for Duke Energy Payroll Company 330 and Duke Energy Payroll Company 110. See further explanation in the attachment.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-50. Provide the most current invoice for each type of insurance contained in Insurance Expense.

RESPONSE: See the information provided by the Company in MFR Item 36. The invoices shown under MFR Item 36 are the most current invoices for each type of insurance expense.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility and Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-51. Provide a copy of all lease agreements contained in Rent Expense.

RESPONSE: Copies of the lease agreements for Piedmont Row Drive LLC and Johnson Poss Government Relations were provided in the Company's response to MFR item 40. The majority of the remaining charges included in rent expense for the test period arise from DEBS (the service company) allocations including, as described in MFR item 58, a charge for return on DEBS assets (PPE, Pension and Inventory) that is charged to Piedmont's gl account 0931008.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Responses provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-52. Provide the gross and net expenses after deducting salary and wages, by month from May 2011 (the end of the last rate case in Docket 11-00144) through March 2020 for all NARUC and FERC accounts 700 through 932.

RESPONSE: See attachment. Note that the requested information for calendar years 2017, 2018 and 2019 is not included in the attachment herein because it was already provided by the Company in its response to MFR Item 29.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-53. Provide a copy of the 2019 property tax bills (due in 2020) for each taxing jurisdiction in Tennessee.

RESPONSE: Please see the attachment.

Name and Title of Preparer: Jack H. Adams, Tax Professional

Name and Title of Responsible Person: Scott Stewart, Tax Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PROPERTY TAX NOTICE

TAX YEAR 2019	CHEATHAM COUNTY	TENNESSEE

	Receipt#	Tax District	2019 Tax Summary
	1100040		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		30,461.0

Property Classification	Assessment
GAS CO.	1,225,588

EY RECIEVED ON
JAN 03 REC'D

County	City
011	

Total Amount Due	30,461.00

Current Assessment Data	
Total Assessment	1,225,588

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

MARGIE JARRELL
CHEATHAM COUNTY TRUSTEE
PO BOX 56
ASHLAND CITY TN 37015
(615) 792-4298

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	ASHLAND CITY, CHEATHAM COUNTY		TENNESSEE
	Receipt#	Tax District	2019 Tax Summary
	1100016	11A01	Property Tax Rate 0.5037

General Parcel Data

Property Address	Tax Amount	
GA000400		5,782.00

Property Classification	Assessment
GAS CO.	1,147,892

County	City
011	030

EY RECIEVED ON

JAN 02 REC'D

Total Amount Due **5,782.00**

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	1,147,892

TAX COLLECTOR

PO BOX 36
ASHLAND CITY TN 37015
(615) 792-4211

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PLEASE RETURN THE TOP PORTION OF THIS BILL WITH YOUR PAYMENT. YOUR CANCELLED CHECK SERVES AS YOUR RECEIPT.

City of Goodlettsville
105 South Main Street | Goodlettsville | TN | 37072
615.851.2200

TO AVOID INTEREST
TAXES MUST BE PAID BY THE LAST DAY OF FEBRUARY
Interest will accrue at 2% per month starting March 1st

PIEDMONT NATURAL GAS COMPANY,
550 SOUTH TRYON STREET
DEC41A
CHARLOTTE NC 28202

RECEIPT NUMBER
2019 190027.0

DUE DATE	AMOUNT DUE
Feb 29,2020	$5,957.62

CUSTOMER ACCOUNT INFORMATION - RETAIN FOR YOUR RECORDS

PARCEL

2019 190027.0 Parcel:GA000400-19 19
Location:

Owner PIEDMONT NATURAL GAS COMPANY,
550 SOUTH TRYON STREET
DEC41A
CHARLOTTE NC 28202

VALUATIONS AND TAXES:	2019 (This Year) Assessed	2019 (This Year) Taxable	2018 (Last Year) Assessed	2018 (Last Year) Taxable
Land	654683	654683	762788	762788
Buildings	0	0	0	0
TOTAL VALUES:	654683	654683	0	762788
NET TAXABLE VALUE:		654683		762788
Net Value Times levy rate per Thousand		9.10000		7.48400
Equals GROSS Tax of		$5,957.62		$5,708.71
NET ANNUAL TAXES:		$5,957.62		$5,708.71

LEGAL DESCRIPTION

EY RECIEVED ON
DEC 3 0 2019

DISTRIBUTION OF YOUR CURRENT YEAR TAXES:

Taxing Authority	Levy %	This year 2019
City Tax - Davidson	9.100	$5,957.62

IF PAID IN	PAY
MAR 2000	$0.00
APR 2000	$0.00
MAY 2000	$0.00
JUN 2000	$0.00
JUL 2000	$0.00
AUG 2000	$0.00
SEP 2000	$0.00
OCT 2000	$0.00
NOV 2000	$0.00
DEC 2000	$0.00
JAN 2000	$0.00
FEB 2000	$0.00

Your payment options are:
By Mail: 105 South Main Street | Goodlettsville | TN | 37072
In Office: Address above; Monday - Friday, 8:00 AM - 4:30 PM
Online: www.goodlettsville.gov (Third party fee will apply. City does not receive any part of this fee.)

2019 Belle Meade Ad Valorem Tax Information

Make check payable to:

City of Belle Meade

4705 Harding Road
Nashville, TN 37205

Tax District: BM
Company Code: GA000400
Property Class: Gas Company

Important: return this portion with your payment

Piedmont Natural Gas Company, Inc.
550 South Tyron Street, DEC41A
Charlotte, NC 28202

TOTAL DUE: $1,568.76

Amount Remitted: _____

Important: retain this portion for your records

2019 Belle Meade Ad Valorem Tax Information

Company Code: GA000400

Property Class: Gas Company

Mailing Address:

Piedmont Natural Gas Company, Inc.
550 South Tyron Street, DEC41A
Charlotte, NC 28202

Assessed Value: $ 522, 920.00
Tax Rate: $ 0.30 cents

AMOUNT DUE: $ 1,568.76

If you wish to receive a receipt, please send a self-addressed envelope with your payment

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079F**
BILL # **2019-1900339**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	392.93	0.00	392.93
GSD GENERAL FUND	1.28800	10,121.81	0.00	10,121.81
GSD DEBT SERVICES	0.29700	2,333.99	0.00	2,333.99
GSD SCHOOL DEBT SERVICE	0.12600	990.18	0.00	990.18
GSD SCHOOL GENERAL PURPOSE	0.99400	7,811.40	0.00	7,811.40
Total Base Tax	**2.7550**	**$ 21,650.31**		**$ 21,650.31**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	785,855.00
Tax Rate		2.7500
Base Tax	$	21,650.00
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	21,650.00

EY RECIEVED ON
JAN 02 REC'D

Payment History

Original Tax Due	21,650.31
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	21,650.00
Current Interest Due	0.00
Total Current Amount Due	21,650.31

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079F	2019-1900339
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 21,650.31
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

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2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079G**
BILL # **2019-1900340**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	327.34	0.00	327.34
GSD GENERAL FUND	1.28800	8,432.32	0.00	8,432.32
GSD DEBT SERVICES	0.29700	1,944.41	0.00	1,944.41
GSD SCHOOL DEBT SERVICE	0.12600	824.90	0.00	824.90
GSD SCHOOL GENERAL PURPOSE	0.99400	6,507.55	0.00	6,507.55
Total Base Tax	**2.7550**	**$ 18,036.52**		**$ 18,036.52**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	654,683.00
Tax Rate		2.7500
Base Tax	$	18,037.00
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	18,037.00

Payment History

Original Tax Due	18,037.00
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	18,037.00
Current Interest Due	0.00
Total Current Amount Due	18,037.00

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079G	2019-1900340
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 18,037.00
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

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2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079B**
BILL # **2019-1900341**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	12.15	0.00	12.15
GSD GENERAL FUND	1.28800	312.86	0.00	312.86
GSD DEBT SERVICES	0.29700	72.14	0.00	72.14
GSD SCHOOL DEBT SERVICE	0.12600	30.61	0.00	30.61
GSD SCHOOL GENERAL PURPOSE	0.99400	241.44	0.00	241.44
Total Base Tax	**2.7550**	**$ 669.20**		**$ 669.20**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	24,290.00
Tax Rate		2.7500
Base Tax	$	669.00
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	669.00

Payment History

Original Tax Due	669.20
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	669.00
Current Interest Due	0.00
Total Current Amount Due	669.20

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079B	2019-1900341
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 669.20
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

3201901900341000000000000000669209

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079M**
BILL # **2019-1900342**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	261.46	0.00	261.46
GSD GENERAL FUND	1.28800	6,735.21	0.00	6,735.21
GSD DEBT SERVICES	0.29700	1,553.07	0.00	1,553.07
GSD SCHOOL DEBT SERVICE	0.12600	658.88	0.00	658.88
GSD SCHOOL GENERAL PURPOSE	0.99400	5,197.82	0.00	5,197.82
Total Base Tax	**2.7550**	**$ 14,406.44**		**$ 14,406.44**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	522,920.00
Tax Rate		2.7500
Base Tax	$	14,406.00
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	14,406.00

Payment History

Original Tax Due	14,406.44
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	14,406.00
Current Interest Due	0.00
Total Current Amount Due	14,406.44

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079M	2019-1900342
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 14,406.44
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

3201901900342000000000000014406448

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079**
BILL # **2019-1900343**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	21,010.91	0.00	21,010.91
GSD GENERAL FUND	1.28800	541,241.13	0.00	541,241.13
GSD DEBT SERVICES	0.29700	124,804.83	0.00	124,804.83
GSD SCHOOL DEBT SERVICE	0.12600	52,947.50	0.00	52,947.50
GSD SCHOOL GENERAL PURPOSE	0.99400	417,696.96	0.00	417,696.96
Total Base Tax	**2.7550**	**$ 1,157,701.33**		**$ 1,157,701.33**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	42,021,827.00
Tax Rate		2.7500
Base Tax	$	1,157,701.33
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	1,157,701.33

Payment History

Original Tax Due	1,157,701.33
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	1,157,701.33
Current Interest Due	0.00
Total Current Amount Due	1,157,701.33

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079	2019-1900343
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 1,157,701.33
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

3201901900343000000000001157701338

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079O**
BILL # **2019-1900344**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD FIRE PROTECTION	0.05000	287.16	0.00	287.16
GSD GENERAL FUND	1.28800	7,397.27	0.00	7,397.27
GSD DEBT SERVICES	0.29700	1,705.74	0.00	1,705.74
GSD SCHOOL DEBT SERVICE	0.12600	723.65	0.00	723.65
GSD SCHOOL GENERAL PURPOSE	0.99400	5,708.76	0.00	5,708.76
Total Base Tax	**2.7550**	**$ 15,822.58**		**$ 15,822.58**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	574,322.00
Tax Rate		2.7500
Base Tax	$	15,823.00
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	15,823.00

Payment History

Original Tax Due	15,823.00
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	15,823.00
Current Interest Due	0.00
Total Current Amount Due	15,823.00

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U19000790	2019-1900344
PROPERTY ADDRESS DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 15,823.00

To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

3201901900344000000000000015823001

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **12/18/2019 EGOV**
ACCOUNT # **U1900079N**
BILL # **2019-1900345**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 UTILITY PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A

Property Address
DAVIDSON COUNTY GA000400

Classification
Public Utility

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD GENERAL FUND	1.28800	1,112,517.91	0.00	1,112,517.91
GSD DEBT SERVICE	0.29700	256,535.57	0.00	256,535.57
GSD SCHOOL DEBT SERVICE	0.12600	108,833.27	0.00	108,833.27
GSD SCHOOLS GENERAL PURPOSE	0.99400	858,573.60	0.00	858,573.60
USD DEBT SERVICE	0.06600	0.00	57,007.91	57,007.91
USD FIRE PROTECTION	0.05000	43,187.81	0.00	43,187.81
USD GENERAL FUND	0.33400	0.00	288,494.55	288,494.55
Total Base Tax	**3.1550**	**$ 2,379,648.16**	**$ 345,502.46**	**$ 2,725,150.62**

Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	0.00
Exemption		No
Equalization Factor		0.0000
Assessed %		55
Assessed Value	$	86,375,614.00
Tax Rate		3.1550
Base Tax	$	2,725,150.62
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	2,725,150.62

Payment History

Original Tax Due	2,725,150.62
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	2,725,150.62
Current Interest Due	0.00
Total Current Amount Due	2,725,150.62

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
U1900079N	2019-1900345
PROPERTY ADDRESS: DAVIDSON COUNTY GA000400	
AMOUNT REMITTED:	

Current Amount Due : $ 2,725,150.62

To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Metropolitan Trustee
Public Utility Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

32019019003450000000000002725150623

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **10/18/2019 EGOV**
ACCOUNT # **05914003100**
BILL # **2019-60175**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 REAL PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210

Property Address
3115 W HAMILTON AVE

Classification
RESIDENTIAL

Legal Description
LOT 272 SEC 3 TREPPARD HGTS

Acres	Council District
0.48	1

Land Value	$	27,000.00
Improvement Value	$	74,500.00
Personal Property	$	0.00
Total Value	$	101,500.00
Exemption		No
Equalization Factor		0.0000
Assessed %		25
Assessed Value	$	25,375.00
Tax Rate		3.1550
Base Tax	$	800.58
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	800.58

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD GENERAL FUND	1.28800	326.83	0.00	326.83
GSD DEBT SERVICE	0.29700	75.36	0.00	75.36
GSD SCHOOL DEBT SERVICE	0.12600	31.97	0.00	31.97
GSD SCHOOLS GENERAL PURPOSE	0.99400	252.23	0.00	252.23
USD DEBT SERVICE	0.06600	0.00	16.75	16.75
USD FIRE PROTECTION	0.05000	12.69	0.00	12.69
USD GENERAL FUND	0.33400	0.00	84.75	84.75
Total Base Tax	**3.1550**	**$ 699.08**	**$ 101.50**	**$ 800.58**

BY RECIEVED ON
NOV 07 2019

Payment History

Original Tax Due	800.58
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	800.58
Current Interest Due	0.00
Total Current Amount Due	800.58

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
05914003100	2019-60175
PROPERTY ADDRESS 3115 W HAMILTON AVE	
AMOUNT REMITTED:	

Current Amount Due : **$ 800.58**
Suggested Monthly Payment: **$ 160.12**

To avoid interest, total tax must be paid in full by: February 29th, 2020

☐ Address Change

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

Metropolitan Trustee
Real Property Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

5042*23*1*****AUTO**MIXED AADC 370
PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210-4269

12019000601750000000000000000800584

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **10/18/2019 EGOV**
ACCOUNT # **05914003200**
BILL # **2019-60176**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 REAL PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210

Property Address
3113 W HAMILTON AVE

Classification
RESIDENTIAL

Legal Description
LOT 271 SEC 3 TREPPARD HGTS

Acres	Council District
0.45	1

Land Value	$	27,000.00
Improvement Value	$	78,900.00
Personal Property	$	0.00
Total Value	$	105,900.00
Exemption		No
Equalization Factor		0.0000
Assessed %		25
Assessed Value	$	26,475.00
Tax Rate		3.1550
Base Tax	$	835.29
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	835.29

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD GENERAL FUND	1.28800	341.00	0.00	341.00
GSD DEBT SERVICE	0.29700	78.63	0.00	78.63
GSD SCHOOL DEBT SERVICE	0.12600	33.36	0.00	33.36
GSD SCHOOLS GENERAL PURPOSE	0.99400	263.16	0.00	263.16
USD DEBT SERVICE	0.06600	0.00	17.47	17.47
USD FIRE PROTECTION	0.05000	13.24	0.00	13.24
USD GENERAL FUND	0.33400	0.00	88.43	88.43
Total Base Tax	**3.1550**	**$ 729.39**	**$ 105.90**	**$ 835.29**

Payment History

Original Tax Due	835.29
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	835.29
Current Interest Due	0.00
Total Current Amount Due	835.29

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
05914003200	2019-60176
PROPERTY ADDRESS 3113 W HAMILTON AVE	
AMOUNT REMITTED:	

Current Amount Due : **$ 835.29**
Suggested Monthly Payment: **$ 167.06**
To avoid interest, total tax must be paid in full by: February 29th, 2020

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

☐ Address Change

5042*23*1*****AUTO**MIXED AADC 370
PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210-4269

Metropolitan Trustee
Real Property Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

12019000601760000000000000000835299

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **10/16/2019 EGOV**
ACCOUNT # **07001005900**
BILL # **2019-72148**

To avoid interest, total tax must be paid in full by: February 29th, 2020

QUESTIONS: (615) 862-6330

2019 REAL PROPERTY TAX STATEMENT

SEE ENCLOSED BROCHURE FOR IMPORTANT TAX INFORMATION. **RETAIN THIS PORTION FOR YOUR TAX RECORDS.**

Owner Address
PIEDMONT NATURAL GAS COMPANY
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210

Property Address
3201 W HAMILTON AVE

Classification
RESIDENTIAL

Legal Description
LOT 282 SEC 4 TREPPARD HGTS

Acres	Council District
1.31	1

Land Value	$	19,200.00
Improvement Value	$	0.00
Personal Property	$	0.00
Total Value	$	19,200.00
Exemption		No
Equalization Factor		0.0000
Assessed %		25
Assessed Value	$	4,800.00
Tax Rate		3.1550
Base Tax	$	151.44
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	151.44

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD GENERAL FUND	1.28800	61.82	0.00	61.82
GSD DEBT SERVICE	0.29700	14.26	0.00	14.26
GSD SCHOOL DEBT SERVICE	0.12600	6.05	0.00	6.05
GSD SCHOOLS GENERAL PURPOSE	0.99400	47.71	0.00	47.71
USD DEBT SERVICE	0.06600	0.00	3.17	3.17
USD FIRE PROTECTION	0.05000	2.40	0.00	2.40
USD GENERAL FUND	0.33400	0.00	16.03	16.03
Total Base Tax	**3.1550**	**$ 132.24**	**$ 19.20**	**$ 151.44**

EY RECIEVED ON
NOV 0 5 2019

Payment History

Original Tax Due	151.44
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	151.44
Current Interest Due	0.00
Total Current Amount Due	151.44

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
07001005900	2019-72148
PROPERTY ADDRESS 3201 W HAMILTON AVE	
AMOUNT REMITTED:	

Current Amount Due : **$ 151.44**

Suggested Monthly Payment: **$ 30.29**

To avoid interest, total tax must be paid in full by: February 29th, 2020

☐ Address Change

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

Metropolitan Trustee
Real Property Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

80941*266*1*****AUTO**MIXED AADC 370
PIEDMONT NATURAL GAS COMPANY
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210-4269

12019000721480000000000000000151445

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

Printed Date: **11/18/2019 HN**
ACCOUNT # **05913013300**
BILL # **2019-59961**
MTG - **SPECIALIZED LOAN SERVICING**
To avoid interest, total tax must be paid in full by: February 29th, 2020
QUESTIONS: (615) 862-6330

2019 REAL PROPERTY TAX STATEMENT

RETAIN THIS PORTION FOR YOUR TAX RECORDS.

BY RECIEVED ON
DEC 03 2019

Owner Address
PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210

Property Address
3129 W HAMILTON AVE

Classification
RESIDENTIAL

Legal Description
LOT 279 SEC 3 TREPPARD HGTS

Acres	Council District
0.84	1

Land Value	$	28,800.00
Improvement Value	$	74,500.00
Personal Property	$	0.00
Total Value	$	103,300.00
Exemption		No
Equalization Factor		0.0000
Assessed %		25
Assessed Value	$	25,825.00
Tax Rate		3.1550
Base Tax	$	814.78
Rollback Tax	$	0.00
Interest Due	$	0.00
Prior Payments	$	0.00
Balance Due	$	814.78

Your taxes are distributed as follows:

Fund Description	Rate	GSD Tax	USD Tax	Amount
GSD GENERAL FUND	1.28800	332.63	0.00	332.63
GSD DEBT SERVICE	0.29700	76.70	0.00	76.70
GSD SCHOOL DEBT SERVICE	0.12600	32.54	0.00	32.54
GSD SCHOOLS GENERAL PURPOSE	0.99400	256.70	0.00	256.70
USD DEBT SERVICE	0.06600	0.00	17.04	17.04
USD FIRE PROTECTION	0.05000	12.91	0.00	12.91
USD GENERAL FUND	0.33400	0.00	86.26	86.26
Total Base Tax	**3.1550**	**$ 711.48**	**$ 103.30**	**$ 814.78**

Payment History

Original Tax Due	814.78
Adjustments	0.00
Interest Accrued	0.00
Previous Base Tax Payments	0.00
Previous Interest Payments	0.00
Current Base Tax Due	814.78
Current Interest Due	0.00
Total Current Amount Due	814.78

The Metropolitan Trustee accepts partial payment of taxes which have not been turned over to the Chancery Court for collection. The tax lien held against the property will remain in effect until the balance of the property tax has been paid in full, pursuant to T.C.A. 67-5-2101 et seq.

ADA (615) 862-6330

CUT OR TEAR ALONG THIS LINE

2019

Parker Toler, Metropolitan Trustee
P.O. Box 196358
Nashville, TN 37219-6358

PAY ONLINE AT: nashville.gov/trustee

ACCOUNT	BILL #
05913013300	2019-59961
PROPERTY ADDRESS 3129 W HAMILTON AVE	
MTG - SPECIALIZED LOAN SERVICING	
AMOUNT REMITTED	

Current Amount Due : **$ 814.78**
Suggested Monthly Payment: **$ 162.96**
To avoid interest, total tax must be paid in full by: February 29th, 2020

☐ Address Change

Important: Return this portion with your payment. Use the address below for current payment only. Make check payable to:

PIEDMONT NATURAL GAS COMPANY, INC.
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28210

Metropolitan Trustee
Real Property Tax Dept.
PO BOX 305012
Nashville, TN 37230-5012

12019000599610000000000000000814789

PROPERTY TAX NOTICE

TAX YEAR 2019	DICKSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary
2200043		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		2,773.00

Property Classification	Assessment
GAS CO.	118,002

County	City
022	

EY RECIEVED ON
DEC 30 2019

Total Amount Due	2,773.00

Current Assessment Data

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

Total Assessment	118,002

GLYNDA B. PENDERGRASS
DICKSON COUNTY TRUSTEE
PO BOX 246
CHARLOTTE TN 37036
(615) 789-7006

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	ROBERTSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary
7400041		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		50,927.00

Property Classification	Assessment
GAS CO.	1,977,099

County	City
074	

Total Amount Due **50,927.00**

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	1,977,099

KENDRA SHELTON
ROBERTSON COUNTY TRUSTEE
515 S BROWN ST
SPRINGFIELD TN 37172
(615) 384-4238

EY RECIEVED ON
DEC 30 2019

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	GREENBRIER, ROBERTSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
7400016	74A05	Property Tax Rate	1.5700

General Parcel Data

Property Address	Tax Amount	
GA000400		15,033.00

Property Classification	Assessment
GAS CO.	957,508

EY RECIEVED ON

DEC 3 0 2019

County	City
074	309

Total Amount Due	15,033.00

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	957,508

CITY OF GREENBRIER
GREENBRIER CITY RECORDER
P O BOX 466
GREENBRIER TN 37073
(615) 643-4531

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	WHITE HOUSE, ROBERTSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
7400008	74A11	Property Tax Rate	1.0362

General Parcel Data

Property Address	Tax Amount	
GA000400		9,467.00

Property Classification	Assessment
GAS CO.	913,632

County	City
074	771

EY RECIEVED ON
DEC 3 0 2019

Total Amount Due	9,467.00

Current Assessment Data

Tax Collection Period
From: 12/16/2019 **To:** 02/29/2020

Total Assessment	913,632

DANNY DAVENPORT
WHITE HOUSE CITY TAXES
105 COLLEGE STREET
WHITE HOUSE TN 37188
(615) 672-4350

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

TAX YEAR: 2019

TAX COLLECTOR'S NAME AND MAILING ADDRESS:

Teb Batey
Rutherford Co Trustee
P.O. Box 1316
Murfreesboro, TN 37133
(615) 898-7705
rctrustee.com

Locations:
Murfreesboro Office:
Public Square
Courthouse Suite 102

Smyrna Office:
205 I Street (off Weakley Ln)
Part-Time Schedule

TAX BILL

Rutherford County Trustee

Receipt Number: 7500116

Piedmont Natural Gas Company, Inc.
Cindy Mobberley, Tax Manager
550 South Tryon Street, Dec41a
Charlotte NC 28202

BY RECIEVED ON
JAN 03 REC'D

ACCOUNT NUMBER:
PARCEL NUMBER: 00-000-GA-000- - -400.00- -000

Public Utility

Property Address:
SubDivision:
Lot Number:

TAXES ARE DUE AND PAYABLE WITHOUT INTEREST:
FROM: 10-01-2019
THRU: 02-29-2020

ACRES/UNITS: 0.0000
CLASSIFICATION:
CITY: 674
ADDITIONAL DESCRIPTION:

PROPERTY TAX INFORMATION

APPRAISAL:	$0
ASSESSMENT @ 0%	$396,467

County Tax Rate per $100 of Assessment:
City Tax Rate per $100 of Assessment:

County Property Tax:	
City Property Tax:	$0.00
Ad-Valorem Taxes:	$9,083.00
Other Taxes:	
Total Taxes:	$9,083.00
Interest:	$0.00
TOTAL DUE:	**$9,083.00**

Total due if postmarked by: 02-29-2020

GENERAL INFORMATION

PAYMENT INFORMATION: Include receipt number on check. Credit/debit payments are accepted in office or online at rctrustee.com. A convenience fee will be charged on any credit/debit transaction. Partial payments are accepted. Please enclose a self addressed stamped envelope to receive a paid receipt.

Notfify the Assessor of Property at 898-7750 of any change in mailing address.
If you sold this property after January 1 and the new owner has assumed the responsibility for paying the taxes, please forward this notice to the new owner.

PROPERTY TAX RELIEF PROGRAM/SENIOR TAX FREEZE PROGRAM
Property tax relief is available to low-income homeowners age 65 or over, homeowners permanently and totally disabled, and certain disabled veterans or their surviving spouse. Senior tax freeze is also available and requires annual renewal, for information or to schedule an appointment contact the Trustee's office.

DELINQUENT TAXES
Interest will be added to any delinquent taxes at a rate of 1.5% per month.

Please retain this portion for your tax records

Tear at line above
Please Return This Portion with Payment

Make check payable to: Rutherford Co Trustee
P.O. Box 1316
Murfreesboro, TN 37133
(615) 898-7705

TAX YEAR: 2019 **Receipt Number: 7500116**

ACCOUNT NUMBER:	
CURRENT TAXES:	$9,083.00
INTEREST:	$0.00
TOTAL DUE:	$9,083.00
Total due if postmarked by:	02-29-2020

Piedmont Natural Gas Company, Inc.
Cindy Mobberley, Tax Manager
550 South Tryon Street, Dec41a
Charlotte NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	LaVERGNE, RUTHERFORD COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
7500046	75A02	Property Tax Rate	0.7100

General Parcel Data

Property Address	Tax Amount	
GA000400		1,959.00

Property Classification	Assessment
GAS CO.	275,980

County	City
075	400

Total Amount Due	1,959.00

BY RECIEVED ON

JAN 02 REC'D

Current Assessment Data

Tax Collection Period

From: 12/16/2019 To: 02/29/2020

Total Assessment	275,980

BECCI STEED
TAX SPECIALIST
5093 MURFREESBORO RD
LAVERGNE TN 37086
(615) 793-3388

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

Sumner - 2019 Property Tax Notice
Cindy Williams

Cindy Williams

Phone Number
( )
Please include phone number when making this payment.

DIST	MAP	GP	C-MAP	PARCEL	SP-INT	I	CITY
0	GA0		GA0	4.00	000		0

Property Address	Tax Bill #	Tax Year	TOTAL DUE
CINDY MOBBERLEY, TAX MANAGER	8300082	2019	$315,657.00

2819838000882

☐ My address has changed, see attached information.

- Date printed: 12/31/2019
- Balance due if paid in December: $315,657.00

Amount Paid

PIEDMONT NATURAL GAS COMPANY, INC.
CINDY MOBBERLEY, TAX MANAGER
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE, NC 28202

Cindy Williams

BY RECIEVED ON
JAN 2 0 REC'D

Please return the top portion along with your check.

Sumner - 2019 Property Tax Notice

DIST	MAP	GP	C-MAP	PARCEL	SP-INT	I	CITY
0	GA0		GA0	4.00	000		0

Phone: (615) 452-1260
To pay your property taxes make checks payable to:
Sumner County Trustee

Your payment options are:

- By mail: 355 Belvedere Dr N, #107, Gallatin, TN 37066

- On our website: http://tnpayments.com/sumner
with an electronic check, credit or debit card (Additional fees will apply).

Date printed: 12/31/2019

Balance due if paid in December: $315,657.00

Sumner County Office
Office Hours
8:00AM - 4:30PM

Property Address		
CINDY MOBBERLEY, TAX MANAGER		
Classification		
Subdivision		
Lot	**Acres** 0.00	**Block**
Additional Description UTILITY GA000400		
Land Value	$	0.00
Improvement Value	$	0.00
Personal Property	$	0.00
Appraised Value	$	0.00
Exemption		No
Equal Factor		
Net Value	$	0.00
Assessed %		0.5500
Assessed Value	$	13,954,794.00
Tax Rate		2.2620
Tax	$	315,657.00
Interest	$	0.00
Rollback Tax	$	0.00
Balance Due	$	315,657.00

PLEASE RETURN THE TOP PORTION OF THIS BILL WITH YOUR PAYMENT. YOUR CANCELLED CHECK SERVES AS YOUR RECEIPT.

City of Goodlettsville
105 South Main Street | Goodlettsville | TN | 37072
615.851.2200

TO AVOID INTEREST
TAXES MUST BE PAID BY THE LAST DAY OF FEBRUARY
Interest will accrue at 2% per month starting March 1st

PIEDMONT NATURAL GAS COMPANY,
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

RECEIPT NUMBER
2019 830009.0

DUE DATE	AMOUNT DUE
Feb 29,2020	$6,965.16

CUSTOMER ACCOUNT INFORMATION - RETAIN FOR YOUR RECORDS

PARCEL

2019 830009.0 Parcel:GA000400 83
Location:

Owner PIEDMONT NATURAL GAS COMPANY,
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

VALUATIONS AND TAXES:	2019 (This Year) Assessed	2019 (This Year) Taxable	2018 (Last Year) Assessed	2018 (Last Year) Taxable
Land	881666	881666	627017	627017
Buildings	0	0	0	0
TOTAL VALUES:	881666	881666	0	627017
NET TAXABLE VALUE:		881666		627017
Net Value Times levy rate per Thousand		7.90000		8.16300
Equals GROSS Tax of		$6,965.16		$5,118.34
NET ANNUAL TAXES:		$6,965.16		$5,118.34

LEGAL DESCRIPTION

DISTRIBUTION OF YOUR CURRENT YEAR TAXES:

Taxing Authority	Levy %	This year 2019
City Tax - Sumner	7.900	$6,965.16

IF PAID IN	PAY
MAR 2000	$0.00
APR 2000	$0.00
MAY 2000	$0.00
JUN 2000	$0.00
JUL 2000	$0.00
AUG 2000	$0.00
SEP 2000	$0.00
OCT 2000	$0.00
NOV 2000	$0.00
DEC 2000	$0.00
JAN 2000	$0.00
FEB 2000	$0.00

Your payment options are:
By Mail: 105 South Main Street | Goodlettsville | TN | 37072
In Office: Address above; Monday - Friday, 8:00 AM - 4:30 PM
Online: www.goodlettsville.gov (Third party fee will apply. City does not receive any part of this fee.)

PROPERTY TAX NOTICE

TAX YEAR 2019	HENDERSONVILLE, SUMNER COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
8300039	83A03	Property Tax Rate	0.9187

General Parcel Data

Property Address	Tax Amount	75,395.00
GA000400		

Property Classification	Assessment
GAS CO.	8,206,735

County	City
083	327

EY RECIEVED ON

JAN 02 REC'D

Total Amount Due	75,395.00

Current Assessment Data	
Total Assessment	8,206,735

Tax Collection Period

From: 12/16/2019 To: 02/29/2020

ROBERT MANNING
FINANCE DIRECTOR
101 MAPLE DR N
HENDERSONVILLE TN 37075
(615) 264-5399

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	MILLERSVILLE, SUMNER COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
8300005	83A04	Property Tax Rate	1.0000

General Parcel Data

Property Address	Tax Amount	
GA000400		550.00

Property Classification	Assessment
GAS CO.	54,962

County	City
083	487

Total Amount Due	550.00

Current Assessment Data

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

Total Assessment	54,962

CITY TAX COLLECTOR
CITY OF MILLERSVILLE
1246 LOUISVILLE HWY
MILLERSVILLE TN 37072
(615) 859-0880

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	WHITE HOUSE, SUMNER COUNTY		TENNESSEE
	Receipt#	Tax District	2019 Tax Summary
	8300006	83A09	Property Tax Rate 1.0362

General Parcel Data

Property Address	Tax Amount	
GA000400		13,762.00

Property Classification	Assessment
GAS CO.	1,328,143

County	City
083	771

BY RECIEVED ON

DEC 30 2019

Total Amount Due **13,762.00**

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	1,328,143

DANNY DAVENPORT
WHITE HOUSE CITY TAXES
105 COLLEGE STREET
WHITE HOUSE TN 37188
(615) 672-4350

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	TROUSDALE COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary
500020		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		30,355.00

Property Classification	Assessment
GAS CO.	1,244,657

County	City
085	

Total Amount Due **30,355.00**

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	1,244,657

CINDY CARMAN
TROUSDALE COUNTY TRUSTEE
328 BROADWAY
ROOM 3
HARTSVILLE TN 37074
(615) 374-2916

EY RECIEVED ON

DEC 30 2019

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	HARTSVILLE, TROUSDALE COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
9500037	85B00	Property Tax Rate	0.8753

General Parcel Data

Property Address	Tax Amount	
GA000400		7,406.00

Property Classification	Assessment
GAS CO.	846,115

County	City
085	323

Total Amount Due	7,406.00

Current Assessment Data	
Total Assessment	846,115

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

CINDY CARMAN
TROUSDALE COUNTY TRUSTEE
328 BROADWAY
ROOM 3
HARTSVILLE TN 37074-1128
615-374-2916

EY RECIEVED ON
DEC 30 2019

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	WILLIAMSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary
9400051		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		234,774.00

Property Classification	Assessment
GAS CO.	10,411,116

EY RECIEVED ON

JAN 08 REC'D

County	City
094	

Total Amount Due 234,774.00

Current Assessment Data

Tax Collection Period

From: 12/16/2019 To: 02/29/2020

Total Assessment	10,411,116

KAREN L. PARIS
WILLIAMSON COUNTY TRUSTEE
P O BOX 648
FRANKLIN TN 37065-0648
(615) 790-5709

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	BRENTWOOD, WILLIAMSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
	94D01	Property Tax Rate	0.3600

General Parcel Data

Property Address	Tax Amount	
GA000400		26,836.00

Property Classification	Assessment
GAS CO.	7,454,553

EY RECIEVED ON

JAN 08 REC'D

County	City
094	086

Total Amount Due	26,836.00

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	7,454,553

KAREN L. PARIS
WILLIAMSON COUNTY TRUSTEE
P O BOX 648
FRANKLIN TN 37065-0648
(615) 790-5709

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	FAIRVIEW, WILLIAMSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
9400010	94D02	Property Tax Rate	0.8765

General Parcel Data

Property Address	Tax Amount	
GA000400		8,100.00

Property Classification	Assessment
GAS CO.	924,085

County	City
094	255

Total Amount Due 8,100.00

Current Assessment Data

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

Total Assessment	924,085

BRANDY JOHNSON
FAIRVIEW CITY RECORDER
7100 CITY CENTER WAY
FAIRVIEW TN 37062-0069
(615) 799-2484

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	FRANKLIN IN 9TH SSD, WILLIAMSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
9400034	94E03	Property Tax Rate	0.4176

General Parcel Data

Property Address	Tax Amount	
GA000400		2,585.00

Property Classification	Assessment
GAS CO.	619,018

EY RECIEVED ON
JAN 08 REC'D

County	City
094	263

Total Amount Due	2,585.00

Current Assessment Data	
Total Assessment	619,018

Tax Collection Period
From: 12/16/2019 To: 02/29/2020

KAREN PARIS
WILLIAMSON COUNTY TRUSTEE
P O BOX 648
FRANKLIN TN 37065-0648
(615) 790-5709

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	NOLENSVILLE, WILLIAMSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
	94D04	Property Tax Rate	0.1500

General Parcel Data

Property Address	Tax Amount	
GA000400		44.00

Property Classification	Assessment
GAS CO.	29,261

EY RECIEVED ON

JAN 08 REC'D

County	City
094	535

Total Amount Due	44.00

Current Assessment Data

Tax Collection Period

From: 12/16/2019 **To:** 02/29/2020

Total Assessment	29,261

KAREN PARIS
WILLIAMSON COUNTY TRUSTEE
P O BOX 648
FRANKLIN TN 37065-0648
(615) 790-5709

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	WILSON COUNTY	TENNESSEE

	Receipt#	Tax District	2019 Tax Summary
	9500078		Property Tax Rate

General Parcel Data

Property Address	Tax Amount	
GA000400		272,242.00

Property Classification	Assessment
GAS CO.	10,808,006

BY RECIEVED ON

JAN 02 REC'D

County	City
095	

Total Amount Due	272,242.00

Current Assessment Data	
Total Assessment	10,808,006

Tax Collection Period

From: 12/16/2019 To: 02/29/2020

JIM MAJOR
WILSON COUNTY TRUSTEE
P O BOX 865
LEBANON TN 37088
(615) 444-0894

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PROPERTY TAX NOTICE

TAX YEAR 2019	MOUNT JULIET, WILSON COUNTY	TENNESSEE

Receipt#	Tax District	2019 Tax Summary	
9500023	95A02	Property Tax Rate	0.1664

General Parcel Data

Property Address	Tax Amount	
GA000400		13,084.00

Property Classification	Assessment
GAS CO.	7,862,693

EY RECIEVED ON

DEC 3 0 2019

County	City
095	508

Total Amount Due	13,084.00

Current Assessment Data

Tax Collection Period

From: 12/16/2019 To: 02/29/2020

Total Assessment	7,862,693

RENEE BASHAM
PROPERTY TAX CLERK
P O BOX 618
MOUNT JULIET TN 37121
(615) 773-6208

PIEDMONT NATURAL GAS COMPANY, INC.
550 SOUTH TRYON STREET, DEC41A
CHARLOTTE NC 28202

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-54. Provide the actual capital structure including short term debt, long term debt, preferred stock, and common equity for each of the twelve months ending December 31, 2015, 2016, 2017, 2018, and 2019 for:

a. Piedmont Natural Gas Company, subsidiary only.

b. Duke Energy Corporation, consolidated.

c. Duke Energy Corporation, parent only.

Include in your response the cost rates for short term and long-term debt, and preferred stock as well as all supporting source documentation, work papers, and calculations.

RESPONSE: See the 7 attachments.

Name and Title of Preparer: Jordan Morgan, Treasury Director

Name and Title of Responsible Person: Jack Sullivan, Director - Corporate Finance and Assistant Treasurer

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-55. Provide the forecasted capital structure including short term debt, long term debt, preferred stock, and common equity for the attrition year ending December 31, 2021 for:

a. Piedmont Natural Gas Company, subsidiary only.

b. Duke Energy Corporation, consolidated.

c. Duke Energy Corporation, parent only.

Include in your response the cost rates for short term and long-term debt, and preferred stock as well as all supporting source documentation, work papers, and calculations.

RESPONSE: For the forecasted Piedmont capital structure and cost rates, please see the following exhibits filed with the direct testimony of Jack Sullivan: Exhibit_(JLS-1), Exhibit_(JLS-2), Exhibit_(JLS-3).

Also see the CONFIDENTIAL attachment, which provides the Projected Capital Structures and Cost Rates for Duke Energy Consolidated and Duke Energy's Parent Company.

Name and Title of Preparer: Jordan Morgan, Treasury Director

Name and Title of Responsible Person: Jack Sullivan, Director - Corporate Finance and Investments, and Assistant Treasurer

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-56. Please provide copies of all documents – including, without limitation, work papers, spreadsheets, summaries, charts, notes, exhibits, articles, journals, treatises, periodicals, publications, reports, records, statements, Internet web pages, or financial information – relied upon by Dylan W. D'Ascendis in preparing his Direct Testimony in this matter.

RESPONSE: See attachments.

Name and Title of Preparer: Dylan D'Ascendis, External Consultant

Name and Title of Responsible Party: Dylan D'Ascendis, External Consultant

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Piedmont Natural Gas Company, Inc.
Index of Workpapers
to Mr. Dylan W. D'Ascendis' Direct Testimony and Exhibit

1. Federal Reserve Press Release, March 3, 2020.

2. Federal Reserve Bank of New York, *Statement Regarding Treasury Reserve Management Purchases and Repurchase Operations*, March 12, 2020.

3. Federal Reserve Press Release, Coordinated Central Bank Action to Enhance the Provision of Global U.S. Dollar Liquidity, March 15, 2020.

4. Federal Reserve Press Release, Implementation Note issued March 15, 2020.

5. Joint Press Release, *Agencies announce two actions to support lending to households and businesses*, March 27, 2020.

6. Federal Reserve Press Release, March 31, 2020.

7. S&P Global Market Intelligence, *Trump signs $484B coronavirus relief package into law*, April 24, 2020.

8. Federal Reserve Press Release, April 6, 2020.

9. Federal Reserve Press Release, April 9, 2020.

10. Federal Reserve Schedule H.4.1.

11. Blue Chip Financial Forecasts, May 1, 2020. [CONFIDENTIAL]

12. U.S. Department of Labor News Release, April 16, 2020.

13. U.S. Department of Labor News Release, April 23, 2020

14. U.S. Bureau of Labor Statistics News Release, May 8, 2020.

15. U.S. Bureau of Economic Analysis News Release, April 29, 2020.

16. S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative*, April 2, 2020.

17. S&P Global Market Intelligence, *S&P credits utilities' moves to bolster liquidity against virus impacts*, May 6, 2020.

18. Morningstar, Correlations *Going to 1: Amid Market Collapse, U.S. Stock Fund Factors Show Little Differentiation*, March 6, 2020.

19. Moody's Investors Service, *Dividends a major source of cash if coronavirus downturn is prolonged*, April 6, 2020.

20. *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

21. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

22. Tennessee Public Utility Commission, Docket No. 19-00028, Order, January 30, 2020.

23. Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

24. Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

25. State of North Carolina Utilities Commission, *In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges*, Docket No. G-5, Sub 565, *Order Approving Rate Increase and Integrity Management Tracker*, October 28, 2016.

26. Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704 in Docket No. 7700, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994.

27. The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016.

28. Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321, 327.

29. Shannon P. Pratt & Roger J. Grabowski, Cost of Capital: Applications and Examples at 586 (4th ed. 2010).

30. Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

31. FERC Docket Nos. EL05-19-002 and ER05-168-001, *Golden Spread Electric Cooperative, Inc., v. Southwestern Public Service Company,* Opinion No. 501, 123 FERC ¶ 61,047, (April 21, 2008).

32. Arkansas Public Service Commission, Docket No. 04-176-U, *In the Matter of the Application of Arkansas Western Gas Company for Approval of a General Change in Rates and Tariffs*, Order No. 6, October 31, 2005.

33. Connecticut Public Utilities Regulatory Authority, Docket No. 14-05-06, *Application of the Connecticut Light and Power Company to Amend Rate Schedules*, Decision, December 17, 2014.

34. Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001.

35. Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

36. Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

37. Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999).

38. Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992).

39. Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

40. 2004 Update of Vander Weide and Carleton Research

41. Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985).

42. Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020. [CONFIDENTIAL]

43. Roger A. Morin, New Regulatory Finance, at 175, 189-191 (2006).

44. Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004.

45. National Bureau of Economic Research, U.S. Business Cycle Expansion and Contractions.

46. Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995.

47. Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

48. 169 FERC ¶ 61,129, Opinion No. 569.

49. 171 FERC ¶ 61,154, Opinion 569-A.

50. Supporting data from Zacks.com

51. Supporting data from Yahoo.com

52. Supporting data from Value Line [CONFIDENTIAL]

53. Supporting data from Blue Chip Financial Forecasts [CONFIDENTIAL]

FEDERAL RESERVE press release

For release at 10 a.m. EST March 3, 2020

The fundamentals of the U.S. economy remain strong. However, the coronavirus poses evolving risks to economic activity. In light of these risks and in support of achieving its maximum employment and price stability goals, the Federal Open Market Committee decided today to lower the target range for the federal funds rate by 1/2 percentage point, to 1 to 1-1/4 percent. The Committee is closely monitoring developments and their implications for the economic outlook and will use its tools and act as appropriate to support the economy.

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Michelle W. Bowman; Lael Brainard; Richard H. Clarida; Patrick Harker; Robert S. Kaplan; Neel Kashkari; Loretta J. Mester; and Randal K. Quarles.

-0-

For media inquiries, call 202-452-2955.

For release at 10 a.m. EST March 3, 2020

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 3, 2020:

- The Board of Governors of the Federal Reserve System voted unanimously to set the interest rate paid on required and excess reserve balances at 1.10 percent, effective March 4, 2020.

- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

> "Effective March 4, 2020, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 1 to 1-1/4 percent. In light of recent and expected increases in the Federal Reserve's non-reserve liabilities, the Committee directs the Desk to continue purchasing Treasury bills at least into the second quarter of 2020 to maintain over time ample reserve balances at or above the level that prevailed in early September 2019. The Committee also directs the Desk to continue conducting term and overnight repurchase agreement operations at least through April 2020 to ensure that the supply of reserves remains ample even during periods of sharp increases in non-reserve liabilities, and to mitigate the risk of money market pressures that could adversely affect policy implementation. In addition, the Committee directs the Desk to conduct overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 1.00 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.
>
> The Committee directs the Desk to continue rolling over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and to continue reinvesting all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month. Principal payments from agency debt and agency mortgage-backed securities up to $20 billion per month will continue to be reinvested in Treasury securities to roughly match the maturity composition of Treasury securities outstanding; principal payments in excess of $20 billion per month will continue to be reinvested in agency mortgage-backed securities. Small deviations from these amounts for operational reasons are acceptable.

The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/2 percentage point decrease in the primary credit rate to 1.75 percent, effective March 4, 2020. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Minneapolis and New York.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

FEDERAL RESERVE BANK *of* NEW YORK *Serving the Second District and the Nation*

OPERATING POLICY

Statement Regarding Treasury Reserve Management Purchases and Repurchase Operations

March 12, 2020

The Open Market Trading Desk (the Desk) at the Federal Reserve Bank of New York has released a new monthly schedule of Treasury securities operations and has updated the current monthly schedule of repurchase agreement (repo) operations. Pursuant to instruction from the Chair in consultation with the FOMC, adjustments have been made to these schedules to address temporary disruptions in Treasury financing markets. The Treasury securities operation schedule includes a change in the maturity composition of purchases to support functioning in the market for U.S. Treasury securities. Term repo operations in large size have been added to enhance functioning of secured U.S. dollar funding markets.

- As a part of its $60 billion reserve management purchases for the monthly period beginning March 13, 2020 and continuing through April 13, 2020, the Desk will conduct purchases across a range of maturities to roughly match the maturity composition of Treasury securities outstanding. Specifically, the Desk plans to distribute reserve management purchases across eleven sectors, including nominal coupons, bills, Treasury Inflation-Protected Securities, and Floating Rate Notes. The distribution of purchases across sectors will be the same distribution as the Desk uses to reinvest principal payments from the Federal Reserve's holdings of agency debt and agency MBS in Treasury securities. The first such purchases will begin tomorrow, March 13, 2020.
- Today, March 12, 2020, the Desk will offer $500 billion in a three-month repo operation at 1:30 pm ET that will settle on March 13, 2020. Tomorrow, the Desk will further offer $500 billion in a three-month repo operation and $500 billion in a one-month repo operation for same day settlement. Three-month and one-month repo operations for $500 billion will be offered on a weekly basis for the remainder of the monthly schedule. The Desk will continue to offer at least $175 billion in daily overnight repo operations and at least $45 billion in two-week term repo operations twice per week over this period.

These changes are being made to address highly unusual disruptions in Treasury financing markets associated with the coronavirus outbreak. Reserve management purchases into the second quarter will continue to be conducted with this maturity allocation. The terms of operations will be adjusted as needed to foster smooth Treasury market functioning and efficient and effective policy implementation.

Detailed information on the schedule of Treasury purchases is provided on the Treasury Securities Operational Details page. Detailed information on the schedule and parameters of term and overnight repo operations are provided on the Repurchase Agreement Operational Details page.

Press Release

March 15, 2020

Coordinated Central Bank Action to Enhance the Provision of U.S. Dollar Liquidity

For release at 5:00 p.m. EDT

Share

The Bank of Canada, the Bank of England, the Bank of Japan, the European Central Bank, the Federal Reserve, and the Swiss National Bank are today announcing a coordinated action to enhance the provision of liquidity via the standing U.S. dollar liquidity swap line arrangements.

These central banks have agreed to lower the pricing on the standing U.S. dollar liquidity swap arrangements by 25 basis points, so that the new rate will be the U.S. dollar overnight index swap (OIS) rate plus 25 basis points. To increase the swap lines' effectiveness in providing term liquidity, the foreign central banks with regular U.S. dollar liquidity operations have also agreed to begin offering U.S. dollars weekly in each jurisdiction with an 84-day maturity, in addition to the 1-week maturity operations currently offered. These changes will take effect with the next scheduled operations during the week of March 16.[1] The new pricing and maturity offerings will remain in place as long as appropriate to support the smooth functioning of U.S. dollar funding markets.

The swap lines are available standing facilities and serve as an important liquidity backstop to ease strains in global funding markets, thereby helping to mitigate the effects of such strains on the supply of credit to households and businesses, both domestically and abroad.

For media inquiries, call 202-452-2955.

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1. Weekly operations are currently held by the Bank of England, the Bank of Japan, the European Central Bank, and the Swiss National Bank. Return to text

Federal Reserve issues FOMC statement

Federal Reserve actions to support the flow of credit to households and businesses

Bank of Canada

Bank of England

Bank of Japan

European Central Bank

Swiss National Bank

Last Update: March 15, 2020

Press Release

March 15, 2020

Implementation Note issued March 15, 2020

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 15, 2020:

- The Board of Governors of the Federal Reserve System voted unanimously to set the interest rate paid on required and excess reserve balances at 0.10 percent, effective March 16, 2020.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 16, 2020, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 0 to 1/4 percent. The Committee directs the Desk to increase over coming months the System Open Market Account holdings of Treasury securities and agency mortgage-backed securities (MBS) by at least $500 billion and by at least $200 billion, respectively. The Committee instructs the Desk to conduct these purchases at a pace appropriate to support the smooth functioning of markets for Treasury securities and agency MBS.

  The Committee also directs the Desk to continue conducting term and overnight repurchase agreement operations to ensure that the supply of reserves remains ample and to support the smooth functioning of short-term U.S. dollar funding markets. In addition, the Committee directs the Desk to conduct overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 0.00 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.

  The Committee directs the Desk to continue rolling over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and to reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month in agency mortgage-backed securities. Small deviations from these amounts for operational reasons are acceptable.

  The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions.

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1-1/2 percentage point decrease in the primary credit rate to 0.25 percent, effective March 16, 2020. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Minneapolis and New York.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website .

Related Content

Statement Regarding Treasury Securities, Agency Mortgage-Backed Securities, and Repurchase Operations

Last Update: March 15, 2020

Joint Press Release

March 27, 2020

Agencies announce two actions to support lending to households and businesses

Board of Governors of the Federal Reserve System

Federal Deposit Insurance Corporation

Office of the Comptroller of the Currency

For release at 12:00 p.m. EDT

Share

The federal bank regulatory agencies today announced two actions to support the U.S. economy and allow banking organizations to continue lending to households and businesses:

- Allowing early adoption of a new methodology on how certain banking organizations are required to measure counterparty credit risk derivatives contracts; and
- Providing an optional extension of the regulatory capital transition for the new credit loss accounting standard.

The "standardized approach for measuring counterparty credit risk" rule, also known as SA-CCR, was finalized by the agencies in November 2019, with an effective date of April 1. It reflects improvements made to the derivatives market since the 2007-2008 financial crisis, such as central clearing and margin requirements. To help improve current market liquidity and smooth disruptions, the agencies will permit banking organizations to early adopt SA-CCR for the reporting period ending March 31.

Additionally, the agencies issued an interim final rule that allows banking organizations to mitigate the effects of the "current expected credit loss," or CECL, accounting standard in their regulatory capital. Banking organizations that are required under U.S. accounting standards to adopt CECL this year can mitigate the estimated cumulative regulatory capital effects for up to two years. This is in addition to the three-year transition period already in place. Alternatively, banking organizations can follow the capital transition rule issued by the banking agencies in February 2019.

The changes will be effective immediately and the agencies will accept comments on the CECL interim final rule for 45 days.

Federal Register notice: Standardized Approach for Calculating the Exposure Amount of Derivative Contracts

Federal Register notice: Regulatory Capital Rule: Revised Transition of the Current Expected Credit Losses Methodology for Allowances

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Related Content

Board Votes

Last Update: March 31, 2020

Press Release

March 31, 2020

Federal Reserve announces establishment of a temporary FIMA Repo Facility to help support the smooth functioning of financial markets

For release at 8:30 a.m. EDT

Share

The Federal Reserve on Tuesday announced the establishment of a temporary repurchase agreement facility for foreign and international monetary authorities (FIMA Repo Facility) to help support the smooth functioning of financial markets, including the U.S. Treasury market, and thus maintain the supply of credit to U.S. households and businesses. The FIMA Repo Facility will allow FIMA account holders, which consist of central banks and other international monetary authorities with accounts at the Federal Reserve Bank of New York, to enter into repurchase agreements with the Federal Reserve. In these transactions, FIMA account holders temporarily exchange their U.S. Treasury securities held with the Federal Reserve for U.S. dollars, which can then be made available to institutions in their jurisdictions. This facility should help support the smooth functioning of the U.S. Treasury market by providing an alternative temporary source of U.S. dollars other than sales of securities in the open market. It should also serve, along with the U.S. dollar liquidity swap lines the Federal Reserve has established with other central banks, to help ease strains in global U.S. dollar funding markets.

The Federal Reserve provides U.S. dollar-denominated banking services to FIMA account holders in support of Federal Reserve objectives and in recognition of the U.S. dollar's predominant role as an international currency. The FIMA Repo Facility, which adds to the range of services the Federal Reserve provides, will be available beginning April 6 and will continue for at least 6 months.

For media inquiries, call 202-452-2955.

FIMA Repo Facility FAQs

Last Update: March 31, 2020

Trump signs $484B coronavirus relief package into law

Friday, April 24, 2020 12:47 PM ET

By Alison Bennett
Market Intelligence

President Donald Trump signed a measure April 24 that will give the Small Business Administration more than $300 billion in new funding for emergency loans to small companies dealing with the economic fallout of the coronavirus.

The action came after the House overwhelmingly passed the $484 billion Paycheck Protection Program and Health Care Enhancement Act on April 23. The Senate passed the bill via unanimous consent April 21.

The measure grants the SBA $310 billion in additional money for its Paycheck Protection Program, designed to provide small businesses with loans of up to $10 million that will be forgiven if 75% of the money is allocated to payroll and 25% to rent, utilities and mortgage interest.

As a result of intense negotiations between Democrats and Republicans, $60 billion of the $310 billion is designated specifically for smaller lenders, which lawmakers hope will ensure the money ends up going to small businesses.

Of that $60 billion, $30 billion will go to loans made by insured depository institutions and credit unions with assets between $10 billion and $50 billion, while the remaining $30 billion will be set aside for loans made by community banks, small insured depository institutions and credit unions with assets less than $10 billion.

That carve-out was welcomed by the Independent Community Bankers of America, which lobbied for specific funding for smaller lenders.

"These funds will help small-business customers in urban, suburban and rural communities weather the COVID-19 emergency," ICBA President and CEO Rebeca Romero Rainey said following the House vote.

The PPP began as part of the $2 trillion Coronavirus Aid, Relief, and Economic Security Act and originally had $349 billion in funds, but that money ran out in less than two weeks. Despite the additional cash infusion, some stakeholders fear the new funding will also run dry quickly due to the large number of loan applications still in the pipeline and a huge wave of new applications expected.

In addition to the PPP money, the new legislation will give the SBA $50 billion for disaster relief loans and $10 billion for emergency Economic Injury Disaster Loan grants. It also clarifies that agricultural enterprises are eligible for PPP loans.

The law will also provide $75 billion for hospitals and $25 billion for coronavirus testing. Democrats had strongly sought more money for state and local governments but were not able to secure it in this relief package.

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Press Release

April 06, 2020

Federal Reserve will establish a facility to facilitate lending to small businesses via the Small Business Administration's Paycheck Protection Program (PPP) by providing term financing backed by PPP loans

For release at 2:00 p.m. EDT

Share

To facilitate lending to small businesses via the Small Business Administration's Paycheck Protection Program (PPP), the Federal Reserve will establish a facility to provide term financing backed by PPP loans. Additional details will be announced this week.

For media inquiries, call 202-452-2955

Last Update: April 06, 2020

Press Release

April 09, 2020

Federal Reserve takes additional actions to provide up to $2.3 trillion in loans to support the economy

For release at 8:30 a.m. EDT

Share

The Federal Reserve on Thursday took additional actions to provide up to $2.3 trillion in loans to support the economy. This funding will assist households and employers of all sizes and bolster the ability of state and local governments to deliver critical services during the coronavirus pandemic.

"Our country's highest priority must be to address this public health crisis, providing care for the ill and limiting the further spread of the virus," said Federal Reserve Board Chair Jerome H. Powell. "The Fed's role is to provide as much relief and stability as we can during this period of constrained economic activity, and our actions today will help ensure that the eventual recovery is as vigorous as possible."

The Federal Reserve's role is guided by its mandate from Congress to promote maximum employment and stable prices, along with its responsibilities to promote the stability of the financial system. In support of these goals, the Federal Reserve is using its full range of authorities to provide powerful support for the flow of credit in the economy.

The actions the Federal Reserve is taking today to support employers of all sizes and communities across the country will:

- Bolster the effectiveness of the Small Business Administration's Paycheck Protection Program (PPP) by supplying liquidity to participating financial institutions through term financing backed by PPP loans to small businesses. The PPP provides loans to small businesses so that they can keep their workers on the payroll. The Paycheck Protection Program Liquidity Facility (PPPLF) will extend credit to eligible financial institutions that originate PPP loans, taking the loans as collateral at face value;
- Ensure credit flows to small and mid-sized businesses with the purchase of up to $600 billion in loans through the Main Street Lending Program. The Department of the Treasury, using funding from the Coronavirus Aid, Relief, and Economic Security Act (CARES Act) will provide $75 billion in equity to the facility;
- Increase the flow of credit to households and businesses through capital markets, by expanding the size and scope of the Primary and Secondary Market Corporate Credit Facilities (PMCCF and SMCCF) as well as the Term Asset-Backed Securities Loan Facility (TALF). These three programs will now support up to $850 billion in credit backed by $85 billion in credit protection provided by the Treasury; and
- Help state and local governments manage cash flow stresses caused by the coronavirus pandemic by establishing a Municipal Liquidity Facility that will offer up to $500 billion in lending to states and municipalities. The Treasury will provide $35 billion of credit protection to the Federal Reserve for the Municipal Liquidity Facility using funds appropriated by the CARES Act.

The Main Street Lending Program will enhance support for small and mid-sized businesses that were in good financial standing before the crisis by offering 4-year loans to companies employing up to 10,000 workers or with revenues of less than $2.5 billion. Principal and interest payments will be deferred for one year. Eligible banks may originate new Main Street loans or use Main Street loans to increase the size of existing loans to

businesses. Banks will retain a 5 percent share, selling the remaining 95 percent to the Main Street facility, which will purchase up to $600 billion of loans. Firms seeking Main Street loans must commit to make reasonable efforts to maintain payroll and retain workers. Borrowers must also follow compensation, stock repurchase, and dividend restrictions that apply to direct loan programs under the CARES Act. Firms that have taken advantage of the PPP may also take out Main Street loans.

The Federal Reserve and the Treasury recognize that businesses vary widely in their financing needs, particularly at this time, and, as the program is being finalized, will continue to seek input from lenders, borrowers, and other stakeholders to make sure the program supports the economy as effectively and efficiently as possible while also safeguarding taxpayer funds. Comments may be sent to the feedback form until April 16.

To support further credit flow to households and businesses, the Federal Reserve will broaden the range of assets that are eligible collateral for TALF. As detailed in an updated term sheet, TALF-eligible collateral will now include the triple-A rated tranches of both outstanding commercial mortgage-backed securities and newly issued collateralized loan obligations. The size of the facility will remain $100 billion, and TALF will continue to support the issuance of asset-backed securities that fund a wide range of lending, including student loans, auto loans, and credit card loans.

The Municipal Liquidity Facility will help state and local governments better manage cash flow pressures in order to continue to serve households and businesses in their communities. The facility will purchase up to $500 billion of short term notes directly from U.S. states (including the District of Columbia), U.S. counties with a population of at least two million residents, and U.S. cities with a population of at least one million residents. Eligible state-level issuers may use the proceeds to support additional counties and cities. In addition to the actions described above, the Federal Reserve will continue to closely monitor conditions in the primary and secondary markets for municipal securities and will evaluate whether additional measures are needed to support the flow of credit and liquidity to state and local governments.

All of the facilities mentioned above are established by the Federal Reserve under the authority of Section 13(3) of the Federal Reserve Act, with approval of the Treasury Secretary.

The Federal Reserve remains committed to using its full range of tools to support the flow of credit to households and businesses to counter the economic impact of the coronavirus pandemic and promote a swift recovery once the disruptions abate.

For media inquiries, call 202-452-2955

Term Sheet: Term Asset-Backed Securities Loan Facility (PDF)

Term Sheet: Primary Market Corporate Credit Facility (PDF)

Term Sheet: Secondary Market Corporate Credit Facility (PDF)

Term Sheet: Municipal Liquidity Facility (PDF)

Term Sheet: Paycheck Protection Program Lending Facility (PDF)

Main Street Lending Program
Term Sheet: Main Street New Loan Facility (PDF)
Term Sheet: Main Street Expanded Loan Facility (PDF)

Related Content

Board Votes

Term Asset-Backed Securities Loan Facility

Primary Market Corporate Credit Facility

Second Market Corporate Credit Facility

Last Update: April 09, 2020

FEDERAL RESERVE statistical release

H.4.1

Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks

February 6, 2020

1. Factors Affecting Reserve Balances of Depository Institutions

Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures			Wednesday Feb 5, 2020
	Week ended Feb 5, 2020	Change from week ended		
		Jan 29, 2020	Feb 6, 2019	
Reserve Bank credit	4,119,939	+ 4,731	+ 133,606	4,128,065
Securities held outright[1]	3,805,473	+ 11,989	- 24,498	3,817,516
U.S. Treasury securities	2,415,837	+ 18,482	+ 210,084	2,427,880
Bills[2]	236,820	+ 13,930	+ 236,820	247,536
Notes and bonds, nominal[2]	2,024,338	+ 3,333	- 45,058	2,025,475
Notes and bonds, inflation-indexed[2]	129,245	+ 1,240	+ 14,476	129,451
Inflation compensation[3]	25,434	- 21	+ 3,846	25,418
Federal agency debt securities[2]	2,347	0	- 62	2,347
Mortgage-backed securities[4]	1,387,289	- 6,492	- 234,520	1,387,289
Unamortized premiums on securities held outright[5]	123,542	- 188	- 14,833	123,542
Unamortized discounts on securities held outright[5]	-13,308	- 14	- 39	-13,333
Repurchase agreements[6]	175,319	- 6,992	+ 175,319	170,250
Loans	6	0	- 9	1
Primary credit	5	- 1	+ 1	0
Secondary credit	0	0	0	0
Seasonal credit	0	0	- 10	1
Other credit extensions	0	0	0	0
Net portfolio holdings of Maiden Lane LLC[7]	0	0	0	0
Float	-344	- 159	- 101	-104
Central bank liquidity swaps[8]	48	- 3	- 18	48
Other Federal Reserve assets[9]	29,203	+ 99	- 2,215	30,145
Foreign currency denominated assets[10]	20,620	+ 108	- 369	20,453
Gold stock	11,041	0	0	11,041
Special drawing rights certificate account	5,200	0	0	5,200
Treasury currency outstanding[11]	50,176	+ 14	+ 379	50,176
Total factors supplying reserve funds	4,206,977	+ 4,854	+ 133,618	4,214,936

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

1. Factors Affecting Reserve Balances of Depository Institutions (continued)

Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures			Wednesday Feb 5, 2020
	Week ended Feb 5, 2020	Change from week ended		
		Jan 29, 2020	Feb 6, 2019	
Currency in circulation[11]	1,792,655	+ 417	+ 89,283	1,794,675
Reverse repurchase agreements[12]	244,544	+ 8,921	- 12,423	239,163
Foreign official and international accounts	240,255	+ 6,519	- 15,116	235,051
Others	4,289	+ 2,402	+ 2,693	4,112
Treasury cash holdings	219	+ 11	- 41	228
Deposits with F.R. Banks, other than reserve balances	480,775	- 32,331	+ 60,261	484,389
Term deposits held by depository institutions	0	0	0	0
U.S. Treasury, General Account	413,322	- 18,739	+ 60,947	416,585
Foreign official	5,182	+ 2	- 62	5,183
Other[13]	62,270	- 13,594	- 626	62,621
Other liabilities and capital[14]	43,768	- 838	+ 76	43,607
Total factors, other than reserve balances, absorbing reserve funds	2,561,960	- 23,821	+ 137,154	2,562,063
Reserve balances with Federal Reserve Banks	1,645,016	+ 28,674	- 3,537	1,652,873

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis.
6. Cash value of agreements.
7. Refer to the note on consolidation accompanying table 5.
8. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
9. Includes accrued interest, which represents the daily accumulation of interest earned, and other accounts receivable. Also, includes Reserve Bank premises and equipment net of allowances for depreciation.
10. Revalued daily at current foreign currency exchange rates.
11. Estimated.
12. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
13. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
14. Includes the liability for earnings remittances due to the U.S. Treasury.

Sources: Federal Reserve Banks and the U.S. Department of the Treasury.

H.4.1

1A. Memorandum Items

Millions of dollars

Memorandum item	Averages of daily figures			Wednesday Feb 5, 2020
	Week ended Feb 5, 2020	Change from week ended		
		Jan 29, 2020	Feb 6, 2019	
Securities held in custody for foreign official and international accounts	3,426,345	- 8,028	- 572	3,435,564
Marketable U.S. Treasury securities[1]	2,979,721	- 5,763	- 57,404	2,989,080
Federal agency debt and mortgage-backed securities[2]	364,874	- 333	+ 45,629	364,953
Other securities[3]	81,750	- 1,931	+ 11,204	81,531
Securities lent to dealers	31,429	+ 2,731	+ 8,977	34,868
Overnight facility[4]	31,429	+ 2,731	+ 8,977	34,868
U.S. Treasury securities	31,429	+ 2,731	+ 8,977	34,868
Federal agency debt securities	0	0	0	0

Note: Components may not sum to totals because of rounding.

1. Includes securities and U.S. Treasury STRIPS at face value, and inflation compensation on TIPS. Does not include securities pledged as collateral to foreign official and international account holders against reverse repurchase agreements with the Federal Reserve presented in tables 1, 4, and 5.
2. Face value of federal agency securities and current face value of mortgage-backed securities, which is the remaining principal balance of the securities.
3. Includes non-marketable U.S. Treasury securities, supranationals, corporate bonds, asset-backed securities, and commercial paper at face value.
4. Face value. Fully collateralized by U.S. Treasury securities.

2. Maturity Distribution of Securities, Loans, and Selected Other Assets and Liabilities, February 5, 2020

Millions of dollars

Remaining Maturity	Within 15 days	16 days to 90 days	91 days to 1 year	Over 1 year to 5 years	Over 5 year to 10 years	Over 10 years	All
Loans	0	1	0	0	0	...	1
U.S. Treasury securities[1]							
Holdings	53,364	115,176	378,638	917,955	319,329	643,419	2,427,880
Weekly changes	+ 25,098	- 20,026	+ 105	+ 9,736	+ 3,731	+ 129	+ 18,772
Federal agency debt securities[2]							
Holdings	0	0	0	0	1,151	1,196	2,347
Weekly changes	0	0	0	0	0	0	0
Mortgage-backed securities[3]							
Holdings	0	1	4	1,394	71,691	1,314,200	1,387,289
Weekly changes	0	+ 1	+ 1	+ 245	+ 815	- 1,060	+ 1
Repurchase agreements[4]	170,250	0	...	...	...	...	170,250
Central bank liquidity swaps[5]	48	0	0	0	0	0	48
Reverse repurchase agreements[4]	239,163	0	...	...	...	...	239,163
Term deposits	0	0	0	...	...	...	0

Note: Components may not sum to totals because of rounding.
...Not applicable.

1. Face value. For inflation-indexed securities, includes the original face value and compensation that adjusts for the effect of inflation on the original face value of such securities.
2. Face value.
3. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
4. Cash value of agreements.
5. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.

H.4.1

3. Supplemental Information on Mortgage-Backed Securities

Millions of dollars

Account name	Wednesday Feb 5, 2020
Mortgage-backed securities held outright[1]	1,387,289
Commitments to buy mortgage-backed securities[2]	7,770
Commitments to sell mortgage-backed securities[2]	0
Cash and cash equivalents[3]	2

1. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
2. Current face value. Generally settle within 180 days and include commitments associated with outright transactions, dollar rolls, and coupon swaps.
3. This amount is included in other Federal Reserve assets in table 1 and in other assets in table 4 and table 5.

H.4.1

4. Consolidated Statement of Condition of All Federal Reserve Banks

Millions of dollars

Assets, liabilities, and capital	Eliminations from consolidation	Wednesday Feb 5, 2020	Change since Wednesday Jan 29, 2020	Change since Wednesday Feb 6, 2019
Assets				
Gold certificate account		11,037	0	0
Special drawing rights certificate account		5,200	0	0
Coin		1,772	+ 5	- 39
Securities, unamortized premiums and discounts, repurchase agreements, and loans		4,097,977	+ 13,854	+ 143,007
Securities held outright[1]		3,817,516	+ 18,773	- 12,414
U.S. Treasury securities		2,427,880	+ 18,772	+ 222,167
Bills[2]		247,536	+ 15,002	+ 247,536
Notes and bonds, nominal[2]		2,025,475	+ 2,354	- 43,921
Notes and bonds, inflation-indexed[2]		129,451	+ 1,446	+ 14,682
Inflation compensation[3]		25,418	- 30	+ 3,870
Federal agency debt securities[2]		2,347	0	- 62
Mortgage-backed securities[4]		1,387,289	+ 1	- 234,520
Unamortized premiums on securities held outright[5]		123,542	+ 15	- 14,739
Unamortized discounts on securities held outright[5]		-13,333	- 27	- 75
Repurchase agreements[6]		170,250	- 4,875	+ 170,250
Loans		1	- 33	- 15
Net portfolio holdings of Maiden Lane LLC[7]		0	0	0
Items in process of collection	(0)	76	+ 22	+ 10
Bank premises		2,193	- 17	- 6
Central bank liquidity swaps[8]		48	- 3	- 18
Foreign currency denominated assets[9]		20,453	- 46	- 441
Other assets[10]		27,952	+ 1,263	- 2,156
Total assets	(0)	4,166,707	+ 15,077	+ 140,357

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

4. Consolidated Statement of Condition of All Federal Reserve Banks (continued)

Millions of dollars

Assets, liabilities, and capital	Eliminations from consolidation	Wednesday Feb 5, 2020	Change since Wednesday Jan 29, 2020	Change since Wednesday Feb 6, 2019
Liabilities				
Federal Reserve notes, net of F.R. Bank holdings		1,746,494	+ 1,897	+ 88,883
Reverse repurchase agreements[11]		239,163	+ 5,759	- 9,067
Deposits	(0)	2,137,263	+ 8,499	+ 60,600
Term deposits held by depository institutions		0	0	0
Other deposits held by depository institutions		1,652,873	+ 40,650	- 5,990
U.S. Treasury, General Account		416,585	- 33,952	+ 62,689
Foreign official		5,183	+ 2	- 61
Other[12]	(0)	62,621	+ 1,798	+ 3,961
Deferred availability cash items	(0)	180	- 549	- 77
Other liabilities and accrued dividends[13]		5,105	- 508	+ 667
Total liabilities	(0)	4,128,205	+ 15,097	+ 141,005
Capital accounts				
Capital paid in		31,677	- 20	- 649
Surplus		6,825	0	0
Other capital accounts		0	0	0
Total capital		38,502	- 20	- 649

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis.
6. Cash value of agreements, which are collateralized by U.S. Treasury and federal agency securities.
7. Refer to the note on consolidation accompanying table 5.
8. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
9. Revalued daily at current foreign currency exchange rates.
10. Includes accrued interest, which represents the daily accumulation of interest earned, and other accounts receivable.
11. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
12. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
13. Includes the liability for earnings remittances due to the U.S. Treasury.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, February 5, 2020

Millions of dollars

Assets, liabilities, and capital	Total	Boston	New York	Philadelphia	Cleveland	Richmond	Atlanta	Chicago	St. Louis	Minneapolis	Kansas City	Dallas	San Francisco
Assets													
Gold certificate account	11,037	351	3,707	327	531	754	1,560	711	328	186	292	890	1,400
Special drawing rights certificate acct.	5,200	196	1,818	210	237	412	654	424	150	90	153	282	574
Coin	1,772	43	54	157	100	236	178	286	36	51	120	207	304
Securities, unamortized premiums and discounts, repurchase agreements, and loans	4,097,977	85,017	2,235,736	99,239	119,896	250,781	280,191	215,109	58,899	35,461	60,766	177,939	478,942
Securities held outright[1]	3,817,516	79,199	2,082,725	92,447	111,691	233,618	261,015	200,387	54,868	33,034	56,608	165,761	446,164
U.S. Treasury securities	2,427,880	50,369	1,324,580	58,795	71,034	148,578	166,002	127,443	34,895	21,009	36,002	105,421	283,753
Bills[2]	247,536	5,135	135,048	5,994	7,242	15,148	16,925	12,994	3,558	2,142	3,671	10,748	28,930
Notes and bonds[3]	2,180,344	45,234	1,189,532	52,801	63,791	133,429	149,077	114,449	31,337	18,867	32,331	94,673	254,823
Federal agency debt securities[2]	2,347	49	1,280	57	69	144	160	123	34	20	35	102	274
Mortgage-backed securities[4]	1,387,289	28,781	756,864	33,595	40,589	84,897	94,853	72,821	19,939	12,005	20,571	60,238	162,136
Unamortized premiums on securities held outright[5]	123,542	2,563	67,401	2,992	3,615	7,560	8,447	6,485	1,776	1,069	1,832	5,364	14,439
Unamortized discounts on securities held outright[5]	-13,333	-277	-7,274	-323	-390	-816	-912	-700	-192	-115	-198	-579	-1,558
Repurchase agreements[6]	170,250	3,532	92,883	4,123	4,981	10,419	11,641	8,937	2,447	1,473	2,525	7,392	19,898
Loans	1	0	0	0	0	0	0	1	0	0	0	0	0
Net portfolio holdings of Maiden Lane LLC[7]	0	0	0	0	0	0	0	0	0	0	0	0	0
Items in process of collection	76	0	0	0	0	0	75	0	0	1	0	0	0
Bank premises	2,193	105	454	91	117	191	202	192	102	93	228	222	196
Central bank liquidity swaps[8]	48	2	15	3	4	10	3	2	1	0	0	1	7
Foreign currency denominated assets[9]	20,453	881	6,492	1,182	1,633	4,361	1,189	854	312	97	198	253	3,002
Other assets[10]	27,952	598	14,757	672	838	1,951	1,892	1,439	516	308	509	1,241	3,230
Interdistrict settlement account	0	+ 10,484	- 60,623	- 12,806	+ 8,703	- 6,172	+ 22,703	+ 4,844	+ 8,590	+ 3,681	+ 6,238	+ 22,008	- 7,651
Total assets	4,166,707	97,676	2,202,410	89,074	132,059	252,525	308,648	223,863	68,934	39,968	68,504	203,043	480,005

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, February 5, 2020 (continued)

Millions of dollars

Assets, liabilities, and capital	Total	Boston	New York	Philadelphia	Cleveland	Richmond	Atlanta	Chicago	St. Louis	Minneapolis	Kansas City	Dallas	San Francisco
Liabilities													
Federal Reserve notes outstanding	1,958,571	60,819	642,988	57,489	93,786	134,241	273,647	126,673	59,429	32,059	54,155	163,965	259,319
Less: Notes held by F.R. Banks	212,077	6,241	51,572	8,917	10,145	17,059	33,082	13,499	5,286	3,055	7,137	19,998	36,086
Federal Reserve notes, net	1,746,494	54,578	591,416	48,573	83,641	117,183	240,565	113,174	54,142	29,004	47,018	143,967	223,233
Reverse repurchase agreements[11]	239,163	4,962	130,481	5,792	6,997	14,636	16,352	12,554	3,437	2,070	3,546	10,385	27,952
Deposits	2,137,263	36,135	1,465,406	33,138	37,921	112,060	49,400	96,311	10,556	8,331	17,358	47,983	222,663
Term deposits held by depository institutions	0	0	0	0	0	0	0	0	0	0	0	0	0
Other deposits held by depository institutions	1,652,873	36,109	1,020,306	33,136	37,842	111,816	49,366	57,575	10,553	8,279	17,325	47,910	222,657
U.S. Treasury, General Account	416,585	0	416,585	0	0	0	0	0	0	0	0	0	0
Foreign official	5,183	2	5,155	2	3	9	2	2	1	0	0	0	6
Other[12]	62,621	24	23,360	0	75	235	32	38,734	2	51	33	73	1
Deferred availability cash items	180	0	0	0	0	0	69	0	0	111	0	0	0
Earnings remittances due to the U.S. Treasury[13]	1,082	15	591	26	34	26	98	52	30	15	20	56	119
Other liabilities and accrued dividends	4,023	158	1,569	158	174	489	268	277	136	137	155	195	309
Total liabilities	4,128,205	95,847	2,189,463	87,687	128,767	244,394	306,752	222,367	68,302	39,667	68,098	202,585	474,275
Capital													
Capital paid in	31,677	1,505	10,653	1,141	2,708	6,690	1,557	1,231	520	248	334	377	4,713
Surplus	6,825	324	2,294	246	583	1,441	338	265	112	53	72	81	1,016
Other capital	0	0	0	0	0	0	0	0	0	0	0	0	0
Total liabilities and capital	4,166,707	97,676	2,202,410	89,074	132,059	252,525	308,648	223,863	68,934	39,968	68,504	203,043	480,005

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, February 5, 2020 (continued)

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Includes the original face value of inflation-indexed securities and compensation that adjusts for the effect of inflation on the original face value of such securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis.
6. Cash value of agreements, which are collateralized by U.S. Treasury and federal agency securities.
7. Refer to the note on consolidation below.
8. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
9. Revalued daily at current foreign currency exchange rates.
10. Includes accrued interest, which represents the daily accumulation of interest earned, and other accounts receivable.
11. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
12. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
13. Represents the estimated weekly remittances due to U.S. Treasury. The amounts on this line represent the residual net earnings that the Federal Reserve Banks remit to the U.S. Treasury after providing for the costs of operations, payment of dividends, and the amount necessary to maintain a $6.825 billion surplus.

Note on consolidation:

On June 26, 2008, the Federal Reserve Bank of New York (FRBNY) extended a loan to Maiden Lane LLC (ML) under the authority of section 13(3) of the Federal Reserve Act. ML was formed to acquire certain assets of Bear Stearns and to manage those assets through time to maximize repayment of the credit extended and minimize disruption to financial markets. On June 14, 2012, the remaining outstanding balance of the senior loan from FRBNY to ML was repaid in full, with interest. On November 15, 2012, the remaining outstanding balance of the subordinated loan from JPMorgan Chase & Co. to ML was repaid in full, with interest. FRBNY was the primary beneficiary of ML because it received any residual returns and could have absorbed any residual losses should they have occurred. Consistent with generally accepted accounting principles, the assets and liabilities of ML were consolidated with the assets and liabilities of FRBNY in the preparation of the statements of condition shown on this release. As a consequence of the consolidation, the extension of credit from FRBNY to ML was eliminated, the net assets of ML appeared as assets on the previous page (and in table 1 and table 4), and the liabilities of ML to entities other than FRBNY, including those with recourse only to the ML portfolio holdings, were included in other liabilities in this table (and table 1 and table 4).

H.4.1

6. Collateral Held against Federal Reserve Notes: Federal Reserve Agents' Accounts

Millions of dollars

Federal Reserve notes and collateral	Wednesday Feb 5, 2020
Federal Reserve notes outstanding	1,958,571
Less: Notes held by F.R. Banks not subject to collateralization	212,077
Federal Reserve notes to be collateralized	1,746,494
Collateral held against Federal Reserve notes	1,746,494
Gold certificate account	11,037
Special drawing rights certificate account	5,200
U.S. Treasury, agency debt, and mortgage-backed securities pledged[1,2]	1,730,257
Other assets pledged	0
Memo:	
Total U.S. Treasury, agency debt, and mortgage-backed securities[1,2]	3,987,766
Less: Face value of securities under reverse repurchase agreements	234,548
U.S. Treasury, agency debt, and mortgage-backed securities eligible to be pledged	3,753,218

Note: Components may not sum to totals because of rounding.

1. Includes face value of U.S. Treasury, agency debt, and mortgage-backed securities held outright, compensation to adjust for the effect of inflation on the original face value of inflation-indexed securities, and cash value of repurchase agreements.
2. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.

FEDERAL RESERVE statistical release

H.4.1

Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks

April 30, 2020

1. Factors Affecting Reserve Balances of Depository Institutions

Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures			Wednesday Apr 29, 2020
	Week ended Apr 29, 2020	Change from week ended		
		Apr 22, 2020	May 1, 2019	
Reserve Bank credit	6,597,655	+ 146,446	+2,725,889	6,616,131
Securities held outright[1]	5,562,498	+ 110,726	+1,839,511	5,578,486
U.S. Treasury securities	3,945,017	+ 81,460	+1,799,810	3,971,419
Bills[2]	326,044	0	+ 325,944	326,044
Notes and bonds, nominal[2]	3,344,204	+ 72,631	+1,336,315	3,367,047
Notes and bonds, inflation-indexed[2]	239,119	+ 7,927	+ 123,913	242,290
Inflation compensation[3]	35,651	+ 902	+ 13,638	36,038
Federal agency debt securities[2]	2,347	0	0	2,347
Mortgage-backed securities[4]	1,615,134	+ 29,266	+ 39,701	1,604,720
Unamortized premiums on securities held outright[5]	281,268	+ 10,255	+ 147,151	283,240
Unamortized discounts on securities held outright[5]	-5,807	+ 636	+ 7,173	-5,711
Repurchase agreements[6]	163,558	- 7,950	+ 163,558	158,202
Foreign official	0	- 1	0	2
Others	163,557	- 7,950	+ 163,557	158,200
Loans	121,384	+ 2,543	+ 121,360	123,028
Primary credit	31,259	- 3,694	+ 31,256	31,759
Secondary credit	0	0	0	0
Seasonal credit	0	0	- 21	0
Primary Dealer Credit Facility	28,618	- 2,648	+ 28,618	25,504
Money Market Mutual Fund Liquidity Facility	47,504	- 2,142	+ 47,504	46,277
Paycheck Protection Program Liquidity Facility	14,003	+ 11,026	+ 14,003	19,488
Other credit extensions	0	0	0	0
Net portfolio holdings of Commercial Paper Funding Facility II LLC[7]	2,921	+ 405	+ 2,921	3,372
Float	-367	- 163	+ 82	-1,397
Central bank liquidity swaps[8]	434,253	+ 27,981	+ 434,198	438,953
Other Federal Reserve assets[9]	37,947	+ 2,012	+ 9,936	37,956
Foreign currency denominated assets[10]	20,440	- 18	- 90	20,525
Gold stock	11,041	0	0	11,041
Special drawing rights certificate account	5,200	0	0	5,200
Treasury currency outstanding[11]	50,275	+ 14	+ 378	50,275
Total factors supplying reserve funds	6,684,611	+ 146,442	+2,726,176	6,703,172

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

1. Factors Affecting Reserve Balances of Depository Institutions (continued)

Millions of dollars

Reserve Bank credit, related items, and reserve balances of depository institutions at Federal Reserve Banks	Averages of daily figures			Wednesday Apr 29, 2020
	Week ended Apr 29, 2020	Change from week ended		
		Apr 22, 2020	May 1, 2019	
Currency in circulation[11]	1,903,433	+ 12,518	+ 175,001	1,910,511
Reverse repurchase agreements[12]	271,307	- 19,297	+ 8,090	269,106
Foreign official and international accounts	266,878	- 15,004	+ 4,234	267,656
Others	4,430	- 4,292	+ 3,857	1,450
Treasury cash holdings	298	- 3	- 33	301
Deposits with F.R. Banks, other than reserve balances	1,286,524	+ 99,931	+ 826,141	1,296,625
Term deposits held by depository institutions	0	0	0	0
U.S. Treasury, General Account	997,507	+ 96,176	+ 597,009	1,076,232
Foreign official	16,317	+ 24	+ 11,073	16,323
Other[13]	272,699	+ 3,730	+ 218,058	204,070
Other liabilities and capital[14]	63,908	- 2,343	+ 19,255	63,116
Total factors, other than reserve balances, absorbing reserve funds	3,525,469	+ 90,804	+1,028,453	3,539,660
Reserve balances with Federal Reserve Banks	3,159,142	+ 55,638	+1,697,723	3,163,512

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis.
6. Cash value of agreements.
7. Refer to the note on consolidation accompanying table 5.
8. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
9. Includes bank premises, accrued interest, and other accounts receivable. Also includes net portfolio holdings of Maiden Lane LLC.
10. Revalued daily at current foreign currency exchange rates.
11. Estimated.
12. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
13. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
14. Includes the liability for earnings remittances due to the U.S. Treasury.

Sources: Federal Reserve Banks and the U.S. Department of the Treasury.

H.4.1

1A. Memorandum Items

Millions of dollars

Memorandum item	Averages of daily figures			Wednesday Apr 29, 2020
	Week ended Apr 29, 2020	Change from week ended		
		Apr 22, 2020	May 1, 2019	
Securities held in custody for foreign official and international accounts	3,337,349	+ 17,160	- 123,874	3,337,612
Marketable U.S. Treasury securities[1]	2,869,708	+ 18,121	- 187,257	2,871,607
Federal agency debt and mortgage-backed securities[2]	382,551	- 3,258	+ 50,597	380,582
Other securities[3]	85,090	+ 2,297	+ 12,786	85,424
Securities lent to dealers	34,358	- 1,535	+ 11,041	37,344
Overnight facility[4]	34,358	- 1,535	+ 11,041	37,344
U.S. Treasury securities	34,358	- 1,535	+ 11,041	37,344
Federal agency debt securities	0	0	0	0

Note: Components may not sum to totals because of rounding.

1. Includes securities and U.S. Treasury STRIPS at face value, and inflation compensation on TIPS. Does not include securities pledged as collateral to foreign official and international account holders against reverse repurchase agreements with the Federal Reserve presented in tables 1, 4, and 5.
2. Face value of federal agency securities and current face value of mortgage-backed securities, which is the remaining principal balance of the securities.
3. Includes non-marketable U.S. Treasury securities, supranationals, corporate bonds, asset-backed securities, and commercial paper at face value.
4. Face value. Fully collateralized by U.S. Treasury securities.

2. Maturity Distribution of Securities, Loans, and Selected Other Assets and Liabilities, April 29, 2020

Millions of dollars

Remaining Maturity	Within 15 days	16 days to 90 days	91 days to 1 year	Over 1 year to 5 years	Over 5 year to 10 years	Over 10 years	All
Loans[1]	15,854	71,712	15,974	19,488	0	...	123,028
U.S. Treasury securities[2]							
Holdings	55,294	249,856	535,821	1,572,472	665,596	892,381	3,971,419
Weekly changes	- 3,575	+ 6,257	+ 7,636	+ 36,080	+ 6,287	+ 9,384	+ 62,067
Federal agency debt securities[3]							
Holdings	0	0	0	0	1,151	1,196	2,347
Weekly changes	0	0	0	0	0	0	0
Mortgage-backed securities[4]							
Holdings	0	0	4	1,845	76,519	1,526,351	1,604,720
Weekly changes	0	0	- 1	- 66	- 819	- 16,882	- 17,767
Commercial paper held by Commercial Paper Funding Facility II LLC[5]	0	3,347	0	...	...	...	3,347
Repurchase agreements[6]	22,752	135,450	...	...	...	...	158,202
Central bank liquidity swaps[7]	21,507	417,446	0	0	0	0	438,953
Reverse repurchase agreements[6]	269,106	0	...	...	...	...	269,106
Term deposits	0	0	0	...	...	...	0

Note: Components may not sum to totals because of rounding.
...Not applicable.

1. Loans includes primary, secondary, and seasonal loans and credit extended through the Primary Dealer Credit Facility, Money Market Mutual Fund Liquidity Facility, Paycheck Protection Program Liquidity Facility, and other credit extensions. Loans exclude the loan from the Federal Reserve Bank of New York (FRBNY) to Commercial Paper Funding Facility II LLC, which was eliminated when preparing the FRBNY's statement of condition consistent with consolidation under generally accepted accounting principles.
2. Face value. For inflation-indexed securities, includes the original face value and compensation that adjusts for the effect of inflation on the original face value of such securities.
3. Face value.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Face value of commercial paper held by Commercial Paper Funding Facility II LLC.
6. Cash value of agreements.
7. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.

H.4.1

3. Supplemental Information on Mortgage-Backed Securities

Millions of dollars

Account name	Wednesday Apr 29, 2020
Mortgage-backed securities held outright[1]	1,604,720
Residential mortgage-backed securities	1,597,206
Commercial mortgage-backed securities	7,514
Commitments to buy mortgage-backed securities[2]	301,251
Commitments to sell mortgage-backed securities[2]	0
Cash and cash equivalents[3]	27

1. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
2. Current face value. Includes residential and commercial mortgage-backed securities. Residential mortgage-backed securities generally settle within 180 calendar days and include commitments associated with outright transactions, dollar rolls, and coupon swaps. Commercial mortgage-backed securities generally settle within three business days.
3. This amount is included in other Federal Reserve assets in table 1 and in other assets in table 4 and table 5.

H.4.1

4. Consolidated Statement of Condition of All Federal Reserve Banks

Millions of dollars

Assets, liabilities, and capital	Eliminations from consolidation	Wednesday Apr 29, 2020	Change since Wednesday Apr 22, 2020	Change since Wednesday May 1, 2019
Assets				
Gold certificate account		11,037	0	0
Special drawing rights certificate account		5,200	0	0
Coin		1,598	- 38	- 72
Securities, unamortized premiums and discounts, repurchase agreements, and loans		6,137,246	+ 51,563	+2,314,417
Securities held outright[1]		5,578,486	+ 44,300	+1,876,752
U.S. Treasury securities		3,971,419	+ 62,067	+1,847,465
Bills[2]		326,044	0	+ 325,944
Notes and bonds, nominal[2]		3,367,047	+ 52,403	+1,380,622
Notes and bonds, inflation-indexed[2]		242,290	+ 8,598	+ 126,929
Inflation compensation[3]		36,038	+ 1,066	+ 13,971
Federal agency debt securities[2]		2,347	0	0
Mortgage-backed securities[4]		1,604,720	- 17,767	+ 29,287
Unamortized premiums on securities held outright[5]		283,240	+ 5,203	+ 149,208
Unamortized discounts on securities held outright[5]		-5,711	+ 417	+ 7,260
Repurchase agreements[6]		158,202	+ 702	+ 158,202
Loans[7]		123,028	+ 940	+ 122,994
Net portfolio holdings of Commercial Paper Funding Facility II LLC[8]		3,372	+ 640	+ 3,372
Items in process of collection	(0)	41	+ 6	- 30
Bank premises		2,208	+ 1	+ 14
Central bank liquidity swaps[9]		438,953	+ 29,241	+ 438,898
Foreign currency denominated assets[10]		20,525	+ 120	- 118
Other assets[11]		35,749	+ 1,262	+ 9,756
Total assets	(0)	6,655,929	+ 82,793	+2,766,238

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

4. Consolidated Statement of Condition of All Federal Reserve Banks (continued)

Millions of dollars

Assets, liabilities, and capital	Eliminations from consolidation	Wednesday Apr 29, 2020	Change since Wednesday Apr 22, 2020	Change since Wednesday May 1, 2019
Liabilities				
Federal Reserve notes, net of F.R. Bank holdings		1,862,131	+ 14,469	+ 179,317
Reverse repurchase agreements[12]		269,106	- 20,186	- 713
Deposits	(0)	4,460,138	+ 87,725	+2,568,121
Term deposits held by depository institutions		0	0	0
Other deposits held by depository institutions		3,163,513	+ 63,533	+1,703,503
U.S. Treasury, General Account		1,076,232	+ 126,233	+ 707,468
Foreign official		16,323	+ 20	+ 11,078
Other[13]	(0)	204,070	- 102,060	+ 146,072
Deferred availability cash items	(0)	1,438	+ 1,097	+ 891
Other liabilities and accrued dividends[14]		24,279	- 318	+ 19,085
Total liabilities	(0)	6,617,091	+ 82,787	+2,766,700
Capital accounts				
Capital paid in		32,013	+ 7	- 462
Surplus		6,825	0	0
Other capital accounts		0	0	0
Total capital		38,838	+ 7	- 462

Note: Components may not sum to totals because of rounding.

1. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.
2. Face value of the securities.
3. Compensation that adjusts for the effect of inflation on the original face value of inflation-indexed securities.
4. Guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. The current face value shown is the remaining principal balance of the securities.
5. Reflects the premium or discount, which is the difference between the purchase price and the face value of the securities that has not been amortized. For U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis.
6. Cash value of agreements, which are collateralized by U.S. Treasury and federal agency securities.
7. Loans includes primary, secondary, and seasonal loans and credit extended through the Primary Dealer Credit Facility, Money Market Mutual Fund Liquidity Facility, Paycheck Protection Program Liquidity Facility, and other credit extensions.
8. Refer to the note on consolidation accompanying table 5.
9. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
10. Revalued daily at current foreign currency exchange rates.
11. Includes accrued interest, which represents the daily accumulation of interest earned, and other accounts receivable. Also includes net portfolio holdings of Maiden Lane LLC.
12. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
13. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
14. Includes the liability for earnings remittances due to the U.S. Treasury.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, April 29, 2020

Millions of dollars

Assets, liabilities, and capital	Total	Boston	New York	Philadelphia	Cleveland	Richmond	Atlanta	Chicago	St. Louis	Minneapolis	Kansas City	Dallas	San Francisco
Assets													
Gold certificates and special drawing rights certificates	16,237	533	5,483	529	761	1,165	2,183	1,137	479	270	450	1,202	2,045
Coin	1,598	36	46	146	89	218	154	266	24	48	105	182	285
Securities, unamortized premiums and discounts, repurchase agreements, and loans[1]	6,137,246	183,327	3,163,269	138,095	188,631	378,874	445,143	342,081	96,161	57,730	97,563	291,516	754,854
Net portfolio holdings of Commercial Paper Funding Facility II LLC[2]	3,372	0	3,372	0	0	0	0	0	0	0	0	0	0
Central bank liquidity swaps[3]	438,953	20,836	147,516	15,796	37,511	92,649	21,771	17,047	7,195	3,437	4,629	5,211	65,356
Foreign currency denominated assets[4]	20,525	974	6,900	738	1,754	4,331	1,018	797	336	161	216	244	3,055
Other assets[5]	37,998	972	18,413	912	1,252	2,699	2,842	2,148	746	488	888	2,044	4,594
Interdistrict settlement account	0	− 59,723	+ 424,296	− 13,489	− 35,000	+ 47,108	− 96,096	− 4,116	− 20,482	− 12,132	− 13,269	+ 4,689	− 221,786
Total assets	6,655,929	146,955	3,769,296	142,727	194,997	527,044	377,014	359,359	84,460	50,002	90,582	305,089	608,403

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, April 29, 2020 (continued)

Millions of dollars

Assets, liabilities, and capital	Total	Boston	New York	Philadelphia	Cleveland	Richmond	Atlanta	Chicago	St. Louis	Minneapolis	Kansas City	Dallas	San Francisco
Liabilities													
Federal Reserve notes, net	1,862,131	57,679	620,774	50,852	84,152	125,645	256,705	120,771	58,943	30,160	50,021	152,523	253,905
Reverse repurchase agreements[6]	269,106	6,043	139,332	6,140	8,419	16,866	19,832	15,031	4,252	2,543	4,279	12,969	33,399
Deposits	4,460,138	81,015	2,978,912	83,973	98,647	375,279	97,579	221,278	20,361	15,336	35,553	138,308	313,897
Depository institutions	3,163,513	80,996	1,827,993	83,971	92,817	374,380	91,102	101,734	20,356	15,265	26,441	134,566	313,891
U.S. Treasury, General Account	1,076,232	0	1,076,232	0	0	0	0	0	0	0	0	0	0
Foreign official	16,323	2	16,296	1	3	8	2	2	1	0	0	0	6
Other[7]	204,070	16	58,391	0	5,826	890	6,475	119,542	4	70	9,112	3,742	1
Earnings remittances due to the U.S. Treasury[8]	1,933	52	985	40	67	154	141	103	19	14	28	88	242
Other liabilities and accrued dividends	23,784	336	16,292	334	415	948	857	680	249	1,624	286	548	1,214
Total liabilities	6,617,091	145,125	3,756,295	141,338	191,700	518,892	375,115	357,862	83,825	49,677	90,168	304,437	602,658
Capital													
Capital paid in	32,013	1,506	10,707	1,143	2,714	6,712	1,561	1,232	523	272	343	571	4,729
Surplus	6,825	324	2,294	246	583	1,441	338	265	112	53	72	81	1,016
Other capital	0	0	0	0	0	0	0	0	0	0	0	0	0
Total liabilities and capital	6,655,929	146,955	3,769,296	142,727	194,997	527,044	377,014	359,359	84,460	50,002	90,582	305,089	608,403

Note: Components may not sum to totals because of rounding. Footnotes appear at the end of the table.

H.4.1

5. Statement of Condition of Each Federal Reserve Bank, April 29, 2020 (continued)

1. Securities include outright holdings of U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities, including securities lent to dealers under the overnight securities lending facility; refer to table 1A. Mortgage-backed securities are guaranteed by Fannie Mae, Freddie Mac, and Ginnie Mae. Unamortized premiums and discounts are the differences between the purchase price and the face value of the securities that have not been amortized. For U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities, amortization is on an effective-interest basis. Repurchase agreements reflect the cash value of agreements, which are collateralized by U.S. Treasury and federal agency securities. Loans includes primary, secondary, and seasonal loans and credit extended through the Primary Dealer Credit Facility, Money Market Mutual Fund Liquidity Facility, Paycheck Protection Program Liquidity Facility, and other credit extensions.
2. Refer to note on consolidation below.
3. Dollar value of foreign currency held under these agreements valued at the exchange rate to be used when the foreign currency is returned to the foreign central bank. This exchange rate equals the market exchange rate used when the foreign currency was acquired from the foreign central bank.
4. Revalued daily at current foreign currency exchange rates.
5. Includes items in process of collection, bank premises, accrued interest (which represents the daily accumulation of interest earned), and other accounts receivable. Also includes Net portfolio holdings of Maiden Lane LLC; refer to the note on consolidation for additional information.
6. Cash value of agreements, which are collateralized by U.S. Treasury securities, federal agency debt securities, and mortgage-backed securities.
7. Includes deposits held at the Reserve Banks by international and multilateral organizations, government-sponsored enterprises, designated financial market utilities, and deposits held by depository institutions in joint accounts in connection with their participation in certain private-sector payment arrangements. Also includes certain deposit accounts other than the U.S. Treasury, General Account, for services provided by the Reserve Banks as fiscal agents of the United States.
8. Represents the estimated weekly remittances due to U.S. Treasury. The amounts on this line represent the residual net earnings that the Federal Reserve Banks remit to the U.S. Treasury after providing for the costs of operations, payment of dividends, and the amount necessary to maintain a $6.825 billion surplus.

Note on consolidation:

On April 14, 2020, the Federal Reserve Bank of New York (FRBNY) began extending loans to the Commercial Paper Funding Facility II LLC (CPFF II LLC) under the authority of section 13(3) of the Federal Reserve Act. CPFF II LLC is a limited liability company formed to purchase three-month U.S dollar-denominated commercial paper by eligible issuers. The assets of the CPFF II LLC are used to secure the loan from the FRBNY and the amount provided by U.S. Treasury as credit protection to the FRBNY.

The FRBNY is the managing member of CPFF II LLC. Consistent with generally accepted accounting principles, the assets and liabilities of the CPFF II LLC have been consolidated with the assets and liabilities of the FRBNY in the preparation of the statements of condition shown on this release. As a consequence of the consolidation, the loan from the FRBNY to CPFF II LLC is eliminated, the net assets of the CPFF II LLC appear as assets on the previous page (and in table 1 and table 4), and the liabilities of the CPFF II LLC to entities other than the FRBNY, including those with recourse only to the portfolio holdings of the CPFF II LLC are included in other liabilities in this table (and table 1 and table 4).

H.4.1

6. Collateral Held against Federal Reserve Notes: Federal Reserve Agents' Accounts

Millions of dollars

Federal Reserve notes and collateral	Wednesday Apr 29, 2020
Federal Reserve notes outstanding	2,022,105
Less: Notes held by F.R. Banks not subject to collateralization	159,974
Federal Reserve notes to be collateralized	1,862,131
Collateral held against Federal Reserve notes	1,862,131
Gold certificate account	11,037
Special drawing rights certificate account	5,200
U.S. Treasury, agency debt, and mortgage-backed securities pledged[1,2]	1,845,894
Other assets pledged	0
Memo:	
Total U.S. Treasury, agency debt, and mortgage-backed securities[1,2]	5,736,689
Less: Face value of securities under reverse repurchase agreements	255,747
U.S. Treasury, agency debt, and mortgage-backed securities eligible to be pledged	5,480,941

Note: Components may not sum to totals because of rounding.

1. Includes face value of U.S. Treasury, agency debt, and mortgage-backed securities held outright, compensation to adjust for the effect of inflation on the original face value of inflation-indexed securities, and cash value of repurchase agreements.
2. Includes securities lent to dealers under the overnight securities lending facility; refer to table 1A.

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

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"COVID Recession": Black Swan Motivates Active Monetary & Fiscal Policy

This time in economic history will forever be marked with footnotes and asterisks denoting the "COVID Recession." This period is unique for the enormous numbers we'll see in the plunge in GDP, the height of the unemployment rate, the magnitude of the federal budget deficit and the rapid surge in the Federal Reserve balance sheet. Footnotes and asterisks are justified because the cause of this recession is not economic; it's a world-wide disease epidemic. It is truly a Black Swan event that precludes conventional economic modeling.

GDP seen down 27.8% in Q2 but up in Q3. As an indication of the uncertainty involved, consider the outlook for GDP in the Blue Chip Financial Forecasts survey during April 27-28: the average of the forecasts for Q2 is -27.8%, with the "highest" -6.0% and the lowest -45.0% (all SAAR). In April, the average estimate was -15.9%. The average for Q3 shows that GDP should return to positive growth, 7.4%, while the range runs from -41.7% to +55.0%. As an indication that those extreme numbers are not totally huge outliers, the bottom ten forecasts average -13.5% and the top ten average +26.1%.

But interest rates fairly steady. Forecasts that are not nearly so extreme are interest rates. Key to this expected stability is the expectation that the Federal Reserve will continue to be very accommodative. This was strongly indicated by the FOMC statement and Chairman Jerome Powell's comments at the press conference following the April 28-29 meeting. He expects that they will leave the key interest rate unchanged for "a good while" at what they call the "lower bound", 0% to 0.25%. The Blue Chip panel believes this could take until the middle of 2021. As we will describe shortly, the Fed is certainly providing support to borrowers, just not through further reductions in the key interest rate to below zero.

The forecast panel believes longer-term interest rates could actually rise somewhat in coming months. The 10-year Treasury yield, currently just under 0.60%, is projected to edge upward by about 10 basis points each quarter, thus reaching 1.00% at about the end of 2020. This trend is lower than the April forecasts by roughly 15-20 basis points. Corporate bond yields, though, would look fairly flat. AAA-rated bonds would dip slightly this quarter and next but return to their recent 2.80% later in the year. Quality spreads are significant, with BBB bonds widening from their recent 100 basis points over AAA to 170. However, consensus forecasts for those mid-quality yields show them holding pretty steady, so the spread over AAA would narrow again during 2021 back toward the more recent amounts. That's obviously as the economy moves through its recovery and risk is seen to be diminishing.

Major credit expansion by Fed. In the midst of the extreme economic conditions, such moderate moves in interest rates, especially in the longer-term, might be surprising. They likely reflect the repeated assurances from the Fed that they will provide and/or support almost whatever credit is needed throughout the economy. The overall result for the Fed's balance sheet is an increase since the end of February of $2.4 trillion or 58% to $6.6 trillion. In a Special Question, the Blue Chip Financial Forecasts panel indicated that they see the Fed's total assets reaching $8.6 trillion by year-end, which would basically mean a doubling of the size of the Fed's balance sheet. Just yesterday, April 30, the Fed published a new term sheet intended to help establish the Main Street Lending Program, the main outreach to small- and medium-sized businesses. Small businesses themselves are eligible for the Paycheck Protection Program, as their own banks can grant loans to them and receive backing from the Federal Reserve. The Fed is also preparing to initiate the Municipal Lending Facility, which would provide up to $500 billion to states, counties and cities in the Fed's first outreach to state and local governments.

Panel says more fiscal support needed. Fiscal policy is very active as well at the present time. The CARES Act provided $2.2 trillion in various aid programs and this was subsequently augmented with $484 billion more. The forecast panel believes overwhelmingly that still more is required to help stabilize the economy; in another Special Question their estimates of the additional amount range from $800 billion to $2.0 trillion, averaging $1.4 trillion. They then estimate the budget deficit this fiscal year at $3.315 trillion compared to $978 billion in fiscal 2019. For fiscal 2021, the deficit would decrease to $2.234 trillion.

The duration of social distancing regulations. The other policy issue at present is the social distancing regulation itself. What will happen as social distancing requirements ease? States are starting very gradually to open up, to permit more businesses to operate and more activities to take place outside the home. In another Special Question, the majority of survey respondents believe that the most strict and moderately strict social distancing requirements could be ended in May. But some participants believe moderate requirements will be maintained through September. Almost everyone believes that so-called relaxed constraints, that is, the opening of all venues and permitting non-essential travel, will not be undone until at least mid-summer or – more likely – October. These notions depend on the incidence of the disease and its severity.

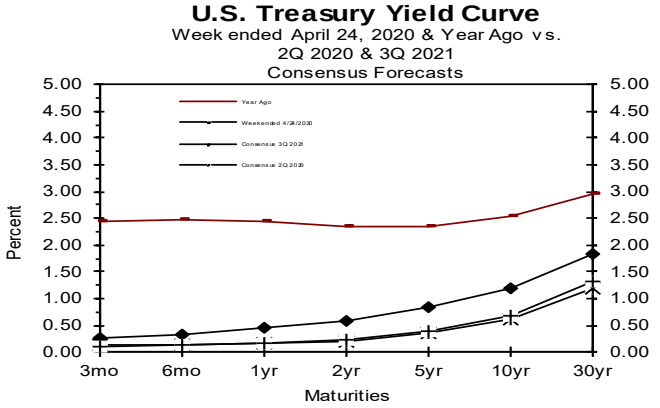
People's willingness to socialize expected to vary. There is one more notable source of uncertainty: what are people actually willing to do even after government mandates have been lifted? Are they willing to go back to work or to sit next to people in a baseball stadium or a movie theater? Fewer members of the Blue Chip panel have views on this, but of the 38 panelists who addressed the Special Questions, 21 of them did respond to it. For the most strict constraints, that is, people who just want to stay home for safety's sake, 16% of the population would feel that way and do so for about seven months. Panelists believe 30% of the population would want to limit their activities, perhaps just going to work or doing required shopping, and they would do that for seven months. Finally those who are most willing to be active in society, with just maintaining some distance would be 48% of the population and they would do so for eight months. Clearly there's no way to gauge the prospects for these strategies, but the feelings that might motivate people do need to be allowed for. To do that, one could be conservative in growth expectations basically until year-end – and then hope there's not a second round of the disease.

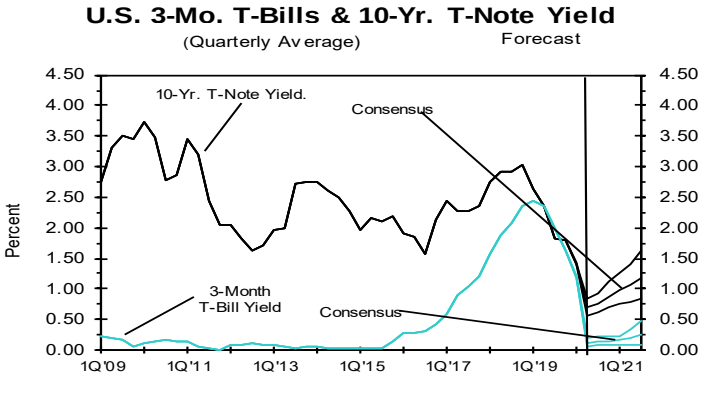
Carol Stone, CBE (Haver Analytics, New York, NY)

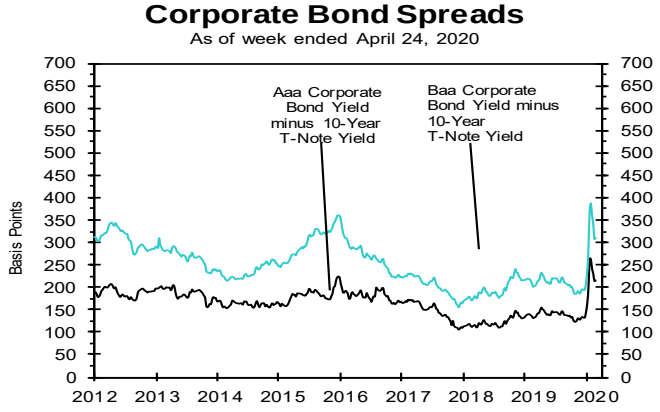
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

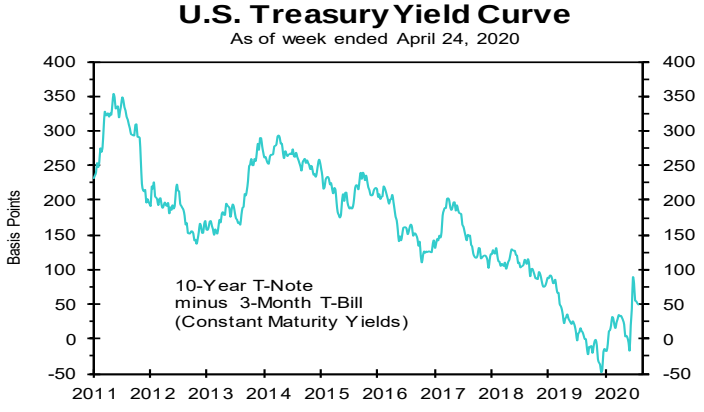
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	Apr 24	Apr 17	Apr 10	Apr 3	Mar	Feb	Jan	1Q 2020	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**
Federal Funds Rate	0.05	0.05	0.05	0.09	0.65	1.58	1.55	1.26	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Prime Rate	3.25	3.25	3.25	3.25	3.81	4.75	4.75	4.44	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**
LIBOR, 3-mo.	1.01	1.14	1.30	1.42	1.10	1.68	1.82	1.53	**0.9**	**0.7**	**0.6**	**0.6**	**0.6**	**0.7**
Commercial Paper, 1-mo.	0.38	0.37	0.37	1.42	1.36	1.55	1.56	1.49	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**	**0.6**
Treasury bill, 3-mo.	0.12	0.17	0.19	0.10	0.30	1.54	1.55	1.13	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**
Treasury bill, 6-mo.	0.14	0.21	0.21	0.14	0.30	1.51	1.56	1.12	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Treasury bill, 1 yr.	0.17	0.21	0.22	0.15	0.33	1.41	1.53	1.09	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**
Treasury note, 2 yr.	0.21	0.22	0.26	0.23	0.45	1.33	1.52	1.10	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	**0.6**
Treasury note, 5 yr.	0.36	0.38	0.45	0.38	0.59	1.32	1.56	1.16	**0.4**	**0.5**	**0.6**	**0.7**	**0.7**	**0.8**
Treasury note, 10 yr.	0.61	0.68	0.73	0.65	0.87	1.50	1.76	1.38	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**
Treasury note, 30 yr.	1.19	1.31	1.33	1.29	1.46	1.97	2.22	1.88	**1.3**	**1.4**	**1.5**	**1.6**	**1.7**	**1.8**
Corporate Aaa bond	2.75	2.81	3.03	3.05	3.11	2.85	3.04	3.00	**2.6**	**2.7**	**2.8**	**2.8**	**2.9**	**3.0**
Corporate Baa bond	3.70	3.75	4.13	4.23	4.11	3.50	3.66	3.76	**4.3**	**4.3**	**4.2**	**4.3**	**4.2**	**4.3**
State & Local bonds	3.37	3.29	3.42	3.45	3.29	2.93	3.00	3.07	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**
Home mortgage rate	3.33	3.31	3.33	3.33	3.45	3.47	3.62	3.51	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.3**
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2018	2018	2018	2019	2019	2019	2019	2020	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**
Fed's AFE $ Index	105.5	107.8	109.4	109.4	110.3	110.5	110.3	111.2	**113.5**	**113.5**	**113.2**	**112.9**	**112.5**	**112.2**
Real GDP	3.5	2.9	1.1	3.1	2.0	2.1	2.1	-4.8	**-27.8**	**7.4**	**9.2**	**6.6**	**4.8**	**3.6**
GDP Price Index	3.2	2.0	1.6	1.1	2.4	1.8	1.3	1.3	**0.1**	**1.1**	**1.3**	**1.7**	**1.9**	**1.8**
Consumer Price Index	2.2	2.1	1.3	0.9	3.0	1.8	2.4	1.2	**-2.4**	**1.1**	**1.7**	**2.1**	**2.1**	**2.1**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).









----------Policy Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.13	0.13	2.38	**0.14**	**0.12**	**0.13**
Japan	-0.10	-0.10	-0.10	**-0.09**	**-0.09**	**-0.09**
U.K.	0.10	0.10	0.75	**0.10**	**0.09**	**0.09**
Switzerland	-0.75	-0.75	-0.75	**-0.75**	**-0.75**	**-0.75**
Canada	0.25	0.25	1.75	**0.25**	**0.25**	**0.25**
Australia	0.25	0.25	1.50	**0.25**	**0.25**	**0.25**
Euro area	0.00	0.00	0.00	**-0.05**	**-0.05**	**-0.05**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.60	0.72	2.51	**0.68**	**0.83**	**1.10**
Germany	-0.47	-0.47	-0.02	**-0.47**	**-0.41**	**-0.27**
Japan	-0.02	0.02	-0.05	**-0.11**	**-0.10**	**-0.07**
U.K.	0.32	0.38	1.18	**0.32**	**0.34**	**0.54**
France	0.03	-0.06	0.35	**0.03**	**0.05**	**0.11**
Italy	1.84	1.36	2.57	**1.81**	**1.74**	**1.69**
Switzerland	-0.43	-0.32	-0.28	**-0.53**	**-0.51**	**-0.47**
Canada	0.58	0.74	1.69	**0.68**	**0.80**	**1.10**
Australia	0.88	0.93	1.78	**0.68**	**0.69**	**0.88**
Spain	1.01	0.60	1.07	**0.80**	**0.76**	**0.76**

----------Foreign Exchange Rates[3]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	114.04	112.99	111.01	**114.7**	**113.6**	**112.1**
Japan	107.44	108.16	111.60	**108.6**	**108.6**	**109.4**
U.K.	1.23	1.24	1.29	**1.23**	**1.24**	**1.28**
Switzerland	0.98	0.96	1.02	**0.96**	**0.96**	**0.96**
Canada	1.41	1.41	1.35	**1.44**	**1.41**	**1.38**
Australia	0.64	0.61	0.70	**0.62**	**0.63**	**0.65**
Euro	1.08	1.11	1.12	**1.09**	**1.10**	**1.12**

	Consensus Policy Rates vs. US Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-0.23	**-0.21**	Germany	-1.07	**-1.37**
U.K.	-0.03	**-0.03**	Japan	-0.62	**-1.17**
Switzerland	-0.88	**-0.88**	U.K.	-0.28	**-0.56**
Canada	0.13	**0.13**	France	-0.57	**-0.99**
Australia	0.13	**0.13**	Italy	1.24	**0.59**
Euro area	-0.13	**-0.18**	Switzerland	-1.03	**-1.57**
			Canada	-0.02	**0.00**
			Australia	0.28	**-0.22**
			Spain	0.41	**-0.34**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International Now comes the hard part—digesting the deluge of dismal economic data. The global economy is likely embarking on the worst recession since the Great Depression with nearly every major government having shut down large parts of its economy to slow the spread of the coronavirus. The Great Lockdown, as named by the IMF, appears to be working as the spread of the virus is slowing down markedly. However, the price has been an abrupt and monumental collapse in economic activity that has never been seen before in the history of modern (post WWII) data collecting.

Flash PMIs for April collapsed to levels well below previous lows. For example, the euro area flash PMI plunged to 13.5 in April, by far the lowest reading on record, vs. a low of 36.2 during the global financial crisis. Moreover, goods-producing sectors are usually the hardest hit during a recession as service-producing sectors typically do not experience the large imbalances that engender retrenchment as do manufacturing and construction. However, in the current environment, the service-producing sectors are being hit even harder than goods-producing sectors as the spread of the virus has led to large parts of the service sectors being shut down.

Monetary and fiscal authorities have responded in size. Where there was room, policy interest rates have been lowered, and our forecast panel expects them to remain there for at least the next 12 months. Furthermore, many central banks have reintroduced, increased, or initiated asset purchase programs (so called quantitative easing) as well as created myriad lending facilities. Market rates have responded with the yield on 10-year government bonds testing all-time lows. Our panel expects these yields to be range-bound for the next six months and then to begin to rise modestly over the ensuing six months.

As the crisis unfolded in the US, the Fed immediately announced a return to QE which was subsequently made limitless, restarted its alphabet soup of lending facilities that had been employed during the global financial crisis and even dreamed up new ones, importantly the Main Street Lending Facility, which it recently extended to include a wider range of businesses and riskier credits, and a lending facility for state and local governments. It has already purchased more than $1.6 trillion of assets since mid-March. Our forecast panel expects the Fed to add another $2 trillion to its balance sheet by the end of this year and another $400 billion in 2021. The $2+ trillion package enacted by US Federal government last month was recently boosted by $450+ billion; our panel looks for another $1.4 trillion of support to come.

After initially responding rather modestly, the Bank of Japan, at its April 27 meeting, announced that there would now be no limits to its asset purchases. It also significantly expanded its credit facilities (a much larger range of collateral and acceptable borrowers). Moreover, the government announced a significant increase in the already large supplemental budget that had been enacted in early April. The European Central Bank and the Bank of England have been relatively quiet lately after having fired policy bazookas in March. Still, the ECB has already purchased nearly €100 billion in securities during April in its new PEPP program and with euro area GDP plunging 3.8% q/q not annualized in Q1, it has just made the terms of the upcoming TLTRO-IIIs (targeted long-term refinancing operations) even more generous and introduced a series of approximately one-year LTROs.

China and Europe are the first to begin to restart their stalled economies and may provide lessons for others. The Chinese economy began to reopen in March but rebounded only modestly from the collapse in February. The official composite PMI rose to 53.0 in March after having fallen to 28.9 in February. This suggests a resumption of previous growth rather than a snapback in activity. Led by Germany, some European economies are just beginning to reopen. European data are not very timely. May PMIs will provide the first look at how the economies have responded—the flash reports are released on May 22.

Second Quarter 2020

Interest Rate Forecasts — Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	1.0	na	na	na	na	0.5 H	0.6	0.9	1.4	na	na	na	na	na	-40.0	-1.8	-4.3
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.3	0.5	0.8	1.3	na	na	na	na	na	-39.0	1.7	-2.0
Via Nova Investment Mgt.	0.3 H	3.3	0.9	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	114.0	-10.0	0.0	-1.0
Economist Intelligence Unit	0.2	3.3	na	0.4	0.2	0.2 H	0.2	0.2	0.3	0.6	1.2	na	na	na	3.3	na	-27.7	na	-4.1
Moody's Analytics	0.2	3.4 H	1.5 H	0.2	0.1	0.1	0.3 H	0.3	0.3	0.4 L	1.5	3.0	4.8	2.8	3.1	na	-30.2	1.6	-4.1
ACIMA Private Wealth	0.1 L	3.3	1.0	1.4	0.0 L	0.0	0.0	0.2	0.4	0.7	1.4	3.5 H	5.5	2.8	3.9 H	113.0	-30.0	1.3	1.5
Action Economics	0.1 L	3.3	1.5 H	0.3	0.1	0.2 H	0.2	0.3	0.5	0.7	1.3	2.8	4.1	2.7	3.6	111.2	-26.0	-2.6	-4.2
AIG	0.1 L	na	na	na	0.0 L	0.0	0.1	0.3	0.4	0.7	1.4	na	4.7	na	3.4	na	-28.0	1.4	0.2
Amherst Pierpont Securities	0.1 L	3.3	0.7	0.1 L	0.1	0.2 H	0.2	0.3	0.5	0.8	1.4	2.5	4.0	2.5	3.4	113.5	-20.0	1.4	-3.1
Bank of America	0.1 L	na	0.6	na	na	na	na	0.2	0.3	0.5	1.0 L	na	na	na	na	na	-30.0	-1.0	-4.0
Barclays	0.1 L	3.3	na	na	na	na	na	0.2	0.5	0.7	1.4	na	na	na	na	na	-45.0 L	-2.3	-5.1
BMO Capital Markets	0.1 L	3.3	1.1	na	0.2	0.2 H	0.3 H	0.3	0.4	0.6	1.2	na	na	na	3.0	115.4 H	-40.0	0.4	-3.9
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	0.3	na	0.8	na	na	na	na	na	na	-30.0	na	0.6
Chan Economics	0.1 L	3.3	0.6	0.7	0.1	0.2 H	0.3 H	0.5 H	0.7 H	0.9	1.5	2.8	4.3	1.9	3.3	114.5	-35.0	1.9 H	2.0 H
Chmura Economics & Analytics	0.1 L	3.2	1.0	0.5	0.1	0.2 H	0.2	0.2	0.4	0.7	1.3	2.5	na	na	3.4	na	-23.6	1.0	1.2
Comerica Bank	0.1 L	3.2	1.4	na	0.1	0.2 H	0.2	0.3	0.4	0.7	1.4	na	na	na	3.8	na	-29.1	0.0	-0.9
Daiwa Capital Markets America	0.1 L	3.3	0.9	0.2	0.1	0.2 H	0.2	0.3	0.5	0.7	1.3	2.4	3.9	na	3.4	114.0	-25.0	1.0	1.0
DePrince & Assoc.	0.1 L	3.1 L	1.0	0.4	0.1	0.2 H	0.2	0.2	0.3	0.6	1.3	2.2	4.3	2.2	3.2	113.4	-12.6	-0.7	-1.6
Fannie Mae	0.1 L	3.3	na	na	0.2	0.2 H	0.2	0.3	0.4	0.7	1.3	na	na	na	3.3	na	-25.3	1.9 H	-3.3
Georgia State University	0.1 L	3.3	na	na	0.2	0.2 H	0.2	0.3	0.4	0.7	1.3	3.3	5.4	na	3.4	na	-31.1	0.4	-2.4
GLC Financial Economics	0.1 L	3.3	0.3 L	0.2	0.0 L	0.1	0.2	0.3	0.4	0.7	1.3	2.8	4.0	2.8	3.5	109.4 L	-32.7	0.0	-1.4
Goldman Sachs & Co.	0.1 L	na	1.0	na	0.3 H	na	na	0.2	0.3	0.6	1.1	na	na	na	3.2	na	-34.0	-0.2	-4.3
Grant Thornton/Diane Swonk	0.1 L	3.3	0.3 L	0.2	0.0 L	-0.1 L	-0.7 L	-0.7 L	-0.2 L	0.5	1.2	1.8 L	5.6 H	na	3.2	na	-28.0	1.0	-6.6 L
ING	0.1 L	na	na	na	na	na	na	0.0	0.2	0.5	1.0 L	na	na	na	na	na	-6.0 H	na	na
Loomis, Sayles & Company	0.1 L	3.3	1.1	0.4	0.2	0.2 H	0.2	0.2	0.4	0.6	1.3	2.5	3.7	3.2	3.3	113.7	-34.0	0.4	-4.9
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3	1.0	0.3	0.1	0.2 H	0.2	0.2	0.4	0.6	1.2	2.8	3.8	3.2	3.3	115.0	-26.6	1.0	-4.5
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.7	na	na	na	na	na	na	na	na	na
Moody's Capital Markets Group	0.1 L	3.3	1.0	0.2	0.1	0.2 H	0.2	0.3	0.5	0.7	1.3	2.6	4.0	2.7	3.3	114.3	-24.3	-0.1	-3.3
MUFG Union Bank	0.1 L	3.3	0.8	na	0.1	0.2 H	0.2	0.3	0.5	0.7	1.3	2.4	3.9	3.0	3.5	114.0	-30.0	1.5	-1.1
Naroff Economic Advisors	0.1 L	3.3	1.2	1.6 H	0.1	0.1	0.2	0.2	0.4	0.7	1.2	2.1	3.1 L	2.3	3.4	114.0	-22.0	0.8	0.2
NatWest Markets	0.1 L	3.3	0.8	0.5	0.2	0.2 H	0.3 H	0.4	0.5	0.9	1.5	3.2	4.4	3.5 H	3.5	113.6	-31.9	-2.0	-5.0
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.3	0.4	0.6	na	na	na	na	na	na	-8.1	1.8	-4.7
Oxford Economics	0.1 L	3.3	1.1	na	0.1	0.1	0.2	0.3	0.3	0.6	1.3	2.3	na	na	3.5	na	-36.1	-1.4	-3.7
PNC Financial Services Corp.	0.1 L	3.3	0.9	na	0.1	0.2 H	0.2	0.2	0.4	0.8	1.4	na	4.1	0.8 L	3.3	na	-30.2	-0.1	-2.8
Regions Financial Corporation	0.1 L	3.3	0.9	na	0.1	0.2 H	0.2	0.2	0.4	0.7	1.2	2.3	4.0	2.4	3.4	113.6	-27.5	-2.9 L	-4.8
S&P Global	0.1 L	na	na	na	0.0 L	0.0	0.0	0.0	0.3	0.7	1.4	na	na	na	3.3	na	-34.6	-2.1	-1.4
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.2	0.4	0.7	1.3	na	na	na	na	na	-30.0	1.3	1.4
Swiss Re	0.1 L	3.3	0.4	0.3	0.2	0.2 H	0.3 H	0.4	0.6	1.0 H	1.7 H	3.4	5.4	na	2.7 L	na	-24.5	-2.9 L	-2.3
The Northern Trust Company	0.1 L	3.3	0.8	0.4	0.1	0.2 H	0.2	0.3	0.4	0.7	1.2	2.5	3.8	3.4	3.2	112.5	-23.0	-0.8	-1.1
Wells Fargo	0.1 L	3.3	0.3 L	0.1 L	0.1	0.1	0.2	0.2	0.4	0.6	1.2	1.8 L	3.9	2.3	3.2	na	-22.3	1.0	-1.7
May Consensus	**0.1**	**3.3**	**0.9**	**0.4**	**0.1**	**0.1**	**0.2**	**0.2**	**0.4**	**0.7**	**1.3**	**2.6**	**4.3**	**2.6**	**3.3**	**113.5**	**-27.8**	**0.1**	**-2.4**
Top 10 Avg.	0.2	3.3	1.2	0.7	0.2	0.2	0.3	0.4	0.5	0.8	1.5	3.1	4.9	3.0	3.6	114.3	-17.2	1.6	0.6
Bottom 10 Avg.	0.1	3.3	0.6	0.2	0.1	0.1	0.1	0.1	0.3	0.6	1.2	2.2	3.8	2.1	3.1	112.8	-37.0	-2.0	-4.8
April Consensus	0.1	3.3	0.8	0.9	0.1	0.1	0.2	0.4	0.6	0.8	1.5	2.9	4.4	2.5	3.3	113.7	-15.9	-0.1	-1.7
Number of Forecasts Changed From A Month Ago:																			
Down	2	4	10	8	2	7	6	22	25	25	23	13	12	5	9	9	34	14	22
Same	35	22	4	5	17	7	13	11	9	10	10	4	3	3	6	1	4	7	6
Up	3	4	13	7	13	17	11	6	4	5	4	5	8	9	14	7	0	14	9
Diffusion Index	51%	50%	56%	48%	67%	66%	58%	29%	22%	25%	24%	32%	41%	62%	59%	44%	5%	50%	32%

Third Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.5	na	na	na	na	0.2 L	0.4	0.7	1.1	na	na	na	na	na	23.0	1.8	1.4
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.4	0.6	0.9	1.5	na	na	na	na	na	25.9	-0.2	-1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.8	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	114.0	-2.5	0.5	1.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.1	0.2	0.2	0.2 L	0.3	0.6	1.2	na	na	na	3.3	na	14.6	na	0.4
ACIMA Private Wealth	0.1 L	3.3 H	1.3 H	1.5	0.0 L	0.0 L	0.0 L	0.2 L	0.4	0.8	1.5	4.0 H	6.5 H	3.0	4.0 H	114.0	-7.5	1.1	-5.0 L
Action Economics	0.1 L	3.3 H	0.6	0.2	0.1	0.2	0.2	0.4	0.6	0.9	1.4	3.0	4.2	3.0	3.6	113.5	19.0	1.6	0.2
AIG	0.1 L	na	na	na	0.0 L	0.1	0.3	0.4	0.5	0.8	1.1	na	4.0	na	3.3	na	3.0	1.2	0.3
Amherst Pierpont Securities	0.1 L	3.3 H	0.4	0.1 L	0.2	0.2	0.3	0.6	0.8 H	1.2 H	1.8 H	2.8	4.2	2.8	3.6	114.0	15.0	2.0	2.9
Bank of America	0.1 L	na	0.5	na	na	na	na	0.3	0.4	0.6	1.2	na	na	na	na	na	-1.0	1.6	2.2
Barclays	0.1 L	3.3 H	na	na	na	na	na	0.2 L	0.5	0.8	1.5	na	na	na	na	na	35.0	1.4	1.4
BMO Capital Markets	0.1 L	3.3 H	0.7	na	0.2	0.3 H	0.3	0.3	0.5	0.7	1.3	na	na	na	2.8	115.8 H	55.0 H	1.7	2.0
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	0.4	na	1.0	na	na	na	na	na	na	5.0	na	0.8
Chan Economics	0.1 L	3.3 H	0.7	0.8	0.1	0.2	0.3	0.5	0.7	0.9	1.5	2.8	4.3	1.9	3.3	114.0	-5.0	2.0	2.1
Chmura Economics & Analytics	0.1 L	3.2	0.9	0.3	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.5	na	na	3.4	na	-7.4	1.2	1.2
Comerica Bank	0.1 L	3.2	0.9	na	0.1	0.2	0.2	0.4	0.5	0.8	1.5	na	na	na	3.6	na	6.3	0.7	0.7
Daiwa Capital Markets America	0.1 L	3.3 H	0.6	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.4	2.4	3.8	na	3.0	113.0	-1.5	1.2	1.8
DePrince & Assoc.	0.1 L	3.1 L	0.8	0.4	0.1	0.2	0.2	0.2 L	0.2 L	0.6	1.3	2.4	4.1	2.3	3.0	112.7	-7.7	0.1	0.1
Fannie Mae	0.1 L	3.3 H	na	na	0.2	0.2	0.2	0.3	0.5	0.7	1.3	na	na	na	3.2	na	7.6	0.6	0.5
Georgia State University	0.1 L	3.3 H	na	na	0.2	0.2	0.2	0.4	0.5	0.7	1.4	3.9	5.1	na	3.2	na	-2.5	2.2	2.8
GLC Financial Economics	0.1 L	3.3 H	0.3 L	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	3.0	4.2	2.9	3.6	110.1	-18.9	0.9	1.1
Goldman Sachs & Co.	0.1 L	na	0.5	na	0.5 H	na	na	0.2 L	0.4	0.5 L	1.0 L	na	na	na	2.8	na	19.0	2.6 H	1.4
Grant Thornton/Diane Swonk	0.1 L	3.3 H	0.3 L	0.2	0.1	0.1	0.6 H	0.7 H	0.6	0.7	1.3	2.0	4.4	na	3.2	na	0.9	1.4	3.5
ING	0.1 L	na	na	na	na	na	na	0.2 L	0.4	0.8	1.3	na	na	na	na	na	-40.0	na	na
Loomis, Sayles & Company	0.1 L	3.3 H	0.9	0.3	0.1	0.2	0.2	0.2 L	0.3	0.6	1.2	2.3	3.3	2.8	3.0	114.0	13.7	0.7	2.4
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3 H	1.0	0.3	0.2	0.2	0.2	0.3	0.4	0.7	1.3	2.8	4.0	3.2	3.4	115.5	-1.0	1.2	3.0
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2	0.9	0.1 L	0.1	0.2	0.4	0.4	0.5	0.6	1.7	2.9	4.5	2.7	3.1	na	16.7	-1.7 L	1.9
Moody's Capital Markets Group	0.1 L	3.3 H	0.9	0.2	0.1	0.2	0.2	0.3	0.6	0.8	1.4	2.5	4.0	2.7	3.2	115.1	12.1	1.1	0.7
MUFG Union Bank	0.1 L	3.3 H	0.6	na	0.1	0.2	0.2	0.3	0.5	0.7	1.2	2.5	4.0	2.9	3.4	115.0	15.0	1.5	1.7
Naroff Economic Advisors	0.1 L	3.3 H	1.2	1.6 H	0.1	0.1	0.2	0.3	0.5	0.7	1.3	2.2	3.1 L	2.4	3.4	114.0	6.0	1.0	0.8
NatWest Markets	0.1 L	3.2	0.8	0.4	0.1	0.2	0.3	0.3	0.5	0.8	1.5	3.0	4.2	3.3 H	3.2	110.0 L	20.3	1.4	2.3
Nomura Securities, Inc.	0.1 L	3.3 H	na	na	na	na	na	0.4	0.5	0.7	na	na	na	na	na	na	-41.7 L	1.6	-1.4
Oxford Economics	0.1 L	3.3 H	0.6	na	0.2	0.2	0.2	0.3	0.5	0.8	1.5	2.1	na	na	3.5	na	7.6	1.5	0.6
PNC Financial Services Corp.	0.1 L	3.3 H	0.3 L	na	0.1	0.2	0.2	0.2 L	0.5	0.8	1.5	na	4.1	0.9 L	3.2	na	13.1	0.1	0.7
Regions Financial Corporation	0.1 L	3.3 H	0.7	na	0.2	0.2	0.2	0.2 L	0.4	0.7	1.3	2.4	4.1	2.5	3.4	113.8	11.1	2.4	4.0 H
S&P Global	0.1 L	na	na	na	0.2	0.2	0.2	0.3	0.6	1.0	1.7	na	na	na	3.5	na	24.1	-1.5	0.3
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.3	0.4	0.6	1.2	na	na	na	na	na	15.0	1.5	1.0
Swiss Re	0.1 L	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.4	5.7	na	2.7 L	na	22.7	1.2	1.1
The Northern Trust Company	0.1 L	3.3 H	0.6	0.4	0.2	0.2	0.2	0.3	0.5	0.8	1.3	2.5	3.8	3.2	2.9	111.0	10.3	0.4	0.5
Wells Fargo	0.1 L	3.3 H	0.3 L	0.1 L	0.1	0.1	0.2	0.3	0.5	0.7	1.3	1.9 L	4.0	2.4	2.9	na	7.2	1.4	1.2
May Consensus	**0.1**	**3.3**	**0.7**	**0.4**	**0.1**	**0.2**	**0.2**	**0.3**	**0.5**	**0.8**	**1.4**	**2.7**	**4.3**	**2.6**	**3.3**	**113.5**	**7.4**	**1.1**	**1.1**
Top 10 Avg.	0.2	3.3	1.0	0.6	0.2	0.2	0.3	0.5	0.6	0.9	1.6	3.2	4.7	3.0	3.6	114.5	26.1	2.0	2.7
Bottom 10 Avg.	0.1	3.2	0.4	0.2	0.1	0.1	0.2	0.2	0.4	0.6	1.2	2.3	3.8	2.2	2.9	112.6	-13.5	0.0	-0.5
April Consensus	0.1	3.3	0.6	0.8	0.1	0.1	0.2	0.4	0.6	0.9	1.5	2.9	4.3	2.5	3.2	113.4	3.1	1.2	1.5
Number of Forecasts Changed From A Month Ago:																			
Down	1	4	9	8	3	6	9	20	21	24	24	10	11	5	9	6	12	15	24
Same	36	22	6	5	20	11	13	13	15	10	10	6	4	3	6	4	6	11	6
Up	3	4	12	7	9	14	8	6	2	6	3	6	8	9	14	7	20	9	7
Diffusion Index	53%	50%	56%	48%	59%	63%	48%	32%	25%	28%	22%	41%	43%	62%	59%	53%	61%	41%	27%

Fourth Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.2 L	0.5	0.9	1.4	na	na	na	na	na	13.0	2.3 H	1.7
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.6	0.9	1.1	1.7	na	na	na	na	na	16.3	-0.7 L	1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.7	0.3	0.2	0.1	0.1	0.3	0.4	0.7 L	1.3	2.9	4.2	1.6	3.2	113.0	5.0	1.0	1.5
Economist Intelligence Unit	0.2	3.3 H	na	0.3	0.2	0.2	0.2	0.2 L	0.3 L	0.7 L	1.2 L	na	na	na	3.4	na	10.8	na	2.5
ACIMA Private Wealth	0.1 L	3.3 H	1.3 H	1.8 H	0.0 L	0.0 L	0.0 L	0.2 L	0.5	0.9	1.7	4.5 H	7.5 H	3.2 H	4.3 H	115.0	9.0	1.0	-1.1
Action Economics	0.1 L	3.3 H	0.6	0.3	0.1	0.2	0.3	0.4	0.7	0.9	1.5	3.1	4.2	3.0	3.6	113.3	10.0	1.7	2.4
AIG	0.1 L	na	na	na	0.1	0.1	0.3	0.4	0.6	0.9	1.2 L	na	3.7	na	3.3	na	12.0	1.2	0.2
Amherst Pierpont Securities	0.1 L	3.3 H	0.5	0.1 L	0.2	0.3 H	0.4 H	0.9 H	1.2 H	1.6 H	2.2 H	3.2	4.5	3.1	3.8	114.5	5.0	2.2	2.8
Bank of America	0.1 L	na	0.5	na	na	na	na	0.5	0.7	1.0	1.6	na	na	na	na	na	30.0 H	1.0	0.5
Barclays	0.1 L	3.3 H	na	na	na	na	na	0.3	0.6	0.9	1.6	na	na	na	na	na	10.0	1.9	2.3
BMO Capital Markets	0.1 L	3.3 H	0.4	na	0.2	0.3 H	0.3	0.4	0.6	0.8	1.5	na	na	na	2.7 L	114.8	5.0	1.7	2.0
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	0.5	na	1.3	na	na	na	na	na	na	10.0	na	0.9
Chan Economics	0.1 L	3.3 H	0.7	0.8	0.1	0.2	0.3	0.5	0.7	0.9	1.5	2.8	4.3	1.9	3.3	113.8	10.0	2.0	2.1
Chmura Economics & Analytics	0.1 L	3.2	0.9	0.2	0.1	0.1	0.2	0.3	0.6	0.9	1.6	2.6	na	na	3.4	na	4.1	1.8	1.8
Comerica Bank	0.1 L	3.2	0.5	na	0.1	0.2	0.3	0.4	0.6	0.8	1.5	na	na	na	3.2	na	12.4	1.1	-0.3
Daiwa Capital Markets America	0.1 L	3.3 H	0.6	0.2	0.2	0.2	0.3	0.3	0.5	0.8	1.4	2.4	3.6	na	2.9	112.0	9.0	1.5	2.2
DePrince & Assoc.	0.1 L	3.1 L	0.5	0.3	0.1	0.2	0.2	0.2 L	0.3 L	0.7 L	1.3	2.6	4.1	2.4	2.9	112.0	2.7	1.0	1.1
Fannie Mae	0.1 L	3.3 H	na	na	0.2	0.2	0.2	0.3	0.5	0.7 L	1.3	na	na	na	3.1	na	13.6	0.9	1.6
Georgia State University	0.1 L	3.3 H	na	na	0.2	0.2	0.2	0.3	0.5	0.9	1.5	4.2	5.5	na	3.4	na	-1.1 L	2.0	2.2
GLC Financial Economics	0.1 L	3.3 H	0.3 L	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.9	4.2	2.8	3.6	110.0	4.1	1.8	2.0
Goldman Sachs & Co.	0.1 L	na	0.5	na	0.4 H	na	na	0.3	0.5	0.7 L	1.2 L	na	na	na	2.9	na	12.0	2.1	3.3 H
Grant Thornton/Diane Swonk	0.1 L	3.3 H	0.4	0.2	0.1	0.1	0.4 H	0.4	0.4	0.7 L	1.5	2.1 L	4.5	na	3.1	na	6.0	1.1	2.8
ING	0.1 L	na	na	na	na	na	na	0.3	0.5	0.8	1.4	na	na	na	na	na	22.0	na	na
Loomis, Sayles & Company	0.1 L	3.3 H	0.7	0.2	0.1	0.1	0.2	0.2 L	0.3 L	0.7 L	1.2 L	2.2	3.0 L	2.5	2.8	113.8	11.2	1.1	3.0
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3 H	1.1	0.4	0.2	0.2	0.3	0.3	0.4	0.7 L	1.3	2.8	4.0	3.2 H	3.4	116.0 H	2.5	1.4	2.1
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2	0.6	0.1 L	0.2	0.2	0.4 H	0.5	0.6	0.7 L	1.9	2.5	3.9	2.4	3.1	na	1.1	0.5	1.8
Moody's Capital Markets Group	0.1 L	3.3 H	0.8	0.2	0.1	0.2	0.3	0.3	0.6	0.9	1.4	2.5	3.8	2.7	3.1	115.4	6.7	1.5	1.9
MUFG Union Bank	0.1 L	3.3 H	0.5	na	0.1	0.1	0.2	0.3	0.5	0.7 L	1.2 L	2.5	4.0	2.8	3.2	116.0 H	7.0	1.5	2.1
Naroff Economic Advisors	0.1 L	3.3 H	1.2	1.6	0.1	0.2	0.2	0.3	0.6	0.9	1.5	2.3	3.3	2.5	3.5	113.0	4.4	1.2	1.0
NatWest Markets	0.1 L	3.2	0.7	0.3	0.1	0.2	0.3	0.3	0.5	1.0	1.6	3.0	4.1	3.1	3.2	108.0 L	7.7	1.5	2.0
Nomura Securities, Inc.	0.1 L	3.3 H	na	na	na	na	na	0.4	0.6	0.8	na	na	na	na	na	na	14.8	1.6	-1.5 L
Oxford Economics	0.1 L	3.3 H	0.4	na	0.2	0.2	0.2	0.3	0.7	1.1	1.8	2.2	na	na	3.6	na	19.3	2.2	3.2
PNC Financial Services Corp.	0.1 L	3.3 H	0.3 L	na	0.1	0.2	0.2	0.2 L	0.5	0.8	1.5	na	4.1	0.9 L	3.1	na	9.5	0.4	1.2
Regions Financial Corporation	0.1 L	3.3 H	0.6	na	0.2	0.3 H	0.3	0.3	0.5	0.8	1.4	2.6	4.2	2.5	3.5	114.1	4.4	2.0	3.3 H
S&P Global	0.1 L	na	na	na	0.2	0.2	0.3	0.4	0.9	1.3	2.0	na	na	na	3.6	na	17.6	0.4	1.6
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.4	0.5	0.7 L	1.3	na	na	na	na	na	7.0	1.0	1.0
Swiss Re	0.1 L	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.4	5.3	na	2.7 L	na	4.1	1.0	2.1
The Northern Trust Company	0.1 L	3.3 H	0.5	0.3	0.2	0.2	0.3	0.4	0.5	0.8	1.3	2.4	3.5	3.0	2.7 L	110.5	5.5	0.8	1.0
Wells Fargo	0.1 L	3.3 H	0.3 L	0.1 L	0.1	0.1	0.2	0.4	0.7	0.9	1.5	2.2	4.2	2.6	2.9	na	4.8	1.8	2.1
May Consensus	**0.1**	**3.3**	**0.6**	**0.4**	**0.1**	**0.2**	**0.3**	**0.4**	**0.6**	**0.9**	**1.5**	**2.8**	**4.2**	**2.6**	**3.2**	**113.2**	**9.2**	**1.3**	**1.7**
Top 10 Avg.	0.2	3.3	0.9	0.6	0.2	0.2	0.3	0.5	0.8	1.1	1.8	3.3	4.8	3.0	3.6	114.7	17.1	2.0	2.8
Bottom 10 Avg.	0.1	3.2	0.4	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.3	2.3	3.7	2.2	2.9	111.9	3.1	0.6	0.3
April Consensus	0.1	3.3	0.6	0.7	0.1	0.2	0.3	0.5	0.7	1.1	1.7	3.0	4.3	2.5	3.3	112.9	5.1	1.5	2.0
Number of Forecasts Changed From A Month Ago:																			
Down	2	5	9	8	4	9	10	20	21	26	23	11	12	6	13	5	4	17	16
Same	35	22	8	8	19	15	14	14	15	11	10	5	3	3	7	6	5	12	9
Up	3	3	10	4	9	7	6	5	2	3	4	6	8	8	9	6	29	6	12
Diffusion Index	51%	47%	52%	40%	58%	47%	43%	31%	25%	21%	24%	39%	41%	56%	43%	53%	83%	34%	45%

First Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.3	0.6	1.0	1.5	na	na	na	na	na	12.0	2.4	1.2
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.7	1.0	1.2	1.9	na	na	na	na	na	10.0	1.3	5.0 H
Via Nova Investment Mgt.	0.3 H	3.3	0.6	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	4.0	1.7	3.3	112.0	4.0	1.5	2.0
Daiwa Capital Markets America	0.2	3.4 H	0.6	0.3	0.2	0.3	0.4	0.5	0.7	1.0	1.5	2.5	3.6	na	3.0	112.0	8.5	1.6	2.0
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.2	0.3	0.4	0.8	1.3	na	na	na	3.4	na	0.8 L	na	1.8
Regions Financial Corporation	0.2	3.3	0.7	na	0.2	0.3	0.4	0.3	0.6	0.9	1.6	2.7	4.4	2.6	3.6	114.7	3.5	1.6	2.6
ACIMA Private Wealth	0.1 L	3.3	1.3 H	1.8 H	0.0 L	0.0 L	0.0 L	0.2 L	0.5	1.0	2.0	4.8 H	8.0 H	3.0	4.0 H	113.0	6.5	0.9 L	3.9
Action Economics	0.1 L	3.3	0.6	0.3	0.2	0.3	0.4	0.5	0.7	1.0	1.5	3.1	4.2	3.0	3.7	112.9	7.5	1.5	2.7
AIG	0.1 L	na	na	na	0.1	0.1	0.4	0.4	0.6	1.0	1.5	na	3.8	na	3.2	na	8.0	1.1	0.3
Amherst Pierpont Securities	0.1 L	3.3	0.6	0.4	0.3	0.4 H	0.8 H	1.2 H	1.7 H	2.1 H	2.6 H	3.6	4.8	3.5 H	4.0 H	115.0	3.6	2.4	2.9
Bank of America	0.1 L	na	0.4	na	na	na	na	0.8	0.9	1.3	1.9	na	na	na	na	na	9.0	1.5	1.7
Barclays	0.1 L	3.3	na	na	na	na	na	0.3	0.6	1.0	1.7	na	na	na	na	na	5.0	1.4	1.0
BMO Capital Markets	0.1 L	3.3	0.4	na	0.2	0.3	0.3	0.4	0.7	1.0	1.6	na	na	na	2.8	113.9	4.9	1.7	1.9
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.6	na	2.2
Chan Economics	0.1 L	3.3	0.7	0.8	0.1	0.2	0.3	0.5	0.7	0.9	1.5	2.8	4.3	1.9	3.3	113.9	5.0	2.0	2.1
Chmura Economics & Analytics	0.1 L	3.2	0.8	0.2	0.1	0.1	0.2	0.4	0.7	1.1	1.7	2.7	na	na	3.4	na	3.2	1.9	2.1
Comerica Bank	0.1 L	3.2	0.5	na	0.1	0.2	0.3	0.4	0.6	0.8	1.4	na	na	na	3.1	na	9.0	1.4	1.2
DePrince & Assoc.	0.1 L	3.1 L	0.5	0.5	0.1	0.1	0.2	0.3	0.3 L	0.8	1.4	2.8	4.0	2.5	2.9	111.4	4.8	1.4	1.5
Fannie Mae	0.1 L	3.3	na	na	0.2	0.2	0.3	0.3	0.5	0.7 L	1.3	na	na	na	3.0	na	8.0	1.0	2.1
Georgia State University	0.1 L	3.3	na	na	0.1	0.2	0.2	0.3	0.7	1.2	1.9	4.5	5.9	na	3.6	na	8.4	2.2	2.5
GLC Financial Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.2 L	2.7	3.9	2.7	3.6	111.0	11.7	2.0	2.3
Goldman Sachs & Co.	0.1 L	na	0.5	na	0.4 H	na	na	na	na	0.8	na	na	na	na	2.9	na	7.5	1.3	2.3
Grant Thornton/Diane Swonk	0.1 L	3.3	0.3 L	0.3	0.1	0.1	0.5	0.4	0.4	0.7 L	1.5	2.1 L	4.3	na	2.9	na	13.3	1.1	2.1
ING	0.1 L	na	na	na	na	na	na	0.6	0.8	1.0	1.7	na	na	na	na	na	10.0	na	na
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.2	0.1	0.1	0.2	0.3	0.4	0.9	1.5	2.2	3.0 L	2.3	2.8	113.6	9.9	1.1	1.7
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3	1.1	0.4	0.2	0.2	0.3	0.3	0.4	0.7 L	1.3	2.8	4.0	3.2	3.4	116.5 H	3.5	1.5	2.0
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2	0.6	0.1 L	0.2	0.3	0.5	0.6	0.8	1.0	2.1	2.5	3.8	2.3	3.2	na	2.2	1.1	4.0
Moody's Capital Markets Group	0.1 L	3.3	0.8	0.2	0.1	0.2	0.3	0.4	0.7	1.0	1.5	2.6	3.8	2.7	3.1	115.6	6.2	1.6	1.9
MUFG Union Bank	0.1 L	3.3	0.3 L	na	0.1	0.1	0.2	0.3	0.5	0.7 L	1.2 L	2.5	4.0	2.7	3.1	115.0	5.0	1.5	2.3
Naroff Economic Advisors	0.1 L	3.3	1.2	1.6	0.2	0.2	0.3	0.4	0.7	1.0	1.6	2.5	3.6	2.7	3.7	113.0	3.5	1.4	1.4
NatWest Markets	0.1 L	3.2	0.5	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.9	3.1	107.0 L	4.4	2.4	3.4
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.5	0.8	1.0	na	na	na	na	na	na	3.2	1.7	0.0 L
Oxford Economics	0.1 L	3.3	0.4	na	0.2	0.2	0.2	0.4	0.8	1.2	1.9	2.2	na	na	3.7	na	23.4 H	2.0	1.8
PNC Financial Services Corp.	0.1 L	3.3	0.3 L	na	0.1	0.2	0.2	0.2 L	0.5	0.9	1.5	na	4.2	1.0 L	3.0	na	7.5	1.1	1.9
S&P Global	0.1 L	na	na	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	7.3	3.8 H	3.9
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.5	0.6	0.8	1.4	na	na	na	na	na	3.0	1.2	1.2
Swiss Re	0.1 L	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.3	4.7	na	2.7	na	2.2	3.1	2.4
The Northern Trust Company	0.1 L	3.3	0.5	0.3	0.2	0.2	0.3	0.5	0.7	0.9	1.4	2.5	3.4	3.2	2.6 L	109.5	4.8	1.2	1.3
Wells Fargo	0.1 L	3.3	0.3 L	0.1 L	0.2	0.2	0.3	0.5	0.8	1.0	1.6	2.3	4.3	2.7	3.0	na	2.8	2.0	2.2
May Consensus	**0.1**	**3.3**	**0.6**	**0.4**	**0.2**	**0.2**	**0.3**	**0.4**	**0.7**	**1.0**	**1.6**	**2.8**	**4.3**	**2.6**	**3.2**	**112.9**	**6.6**	**1.7**	**2.1**
Top 10 Avg.	0.2	3.3	0.8	0.7	0.2	0.3	0.4	0.6	0.9	1.3	2.0	3.3	4.9	3.0	3.7	114.4	11.7	2.4	3.3
Bottom 10 Avg.	0.1	3.2	0.4	0.2	0.1	0.1	0.2	0.3	0.4	0.8	1.3	2.4	3.7	2.2	2.9	111.5	2.7	1.1	1.1
April Consensus	0.2	3.3	0.6	0.7	0.2	0.3	0.4	0.6	0.8	1.2	1.8	3.0	4.3	2.5	3.3	112.4	4.4	1.8	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	7	9	8	8	9	13	10	18	19	24	23	13	14	6	13	4	5	16	10
Same	30	18	10	9	16	11	13	12	15	12	10	4	3	4	8	6	7	13	16
Up	3	3	8	3	7	7	7	6	2	2	2	5	6	7	8	7	25	5	10
Diffusion Index	45%	40%	50%	38%	47%	40%	45%	33%	26%	21%	20%	32%	33%	53%	41%	59%	77%	34%	50%

Second Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Amherst Pierpont Securities	0.6 H	3.7 H	1.0	0.8	0.6 H	0.8 H	1.3 H	1.6 H	2.1 H	2.5 H	3.1 H	4.0	5.2	3.8 H	4.4 H	115.5	3.5	2.3	2.8
Daiwa Capital Markets America	0.5	3.7 H	0.9	0.6	0.5	0.6	0.7	1.0	1.2	1.4	1.9	2.8	3.9	na	3.4	112.0	4.5	1.8	2.2
Moody's Capital Markets Group	0.4	3.5	0.8	0.4	0.4	0.5	0.6	0.7	0.9	1.2	1.6	2.7	3.8	2.7	3.1	115.8	4.4	1.7	1.1
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	6.0	2.4	1.4
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.8	1.1	1.3	2.1	na	na	na	na	na	6.3	2.8	0.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	3.8	1.5	3.3	110.0	3.5	2.0	2.2
Action Economics	0.2	3.3	0.7	0.3	0.3	0.4	0.4	0.5	0.8	1.0	1.5	3.1	4.2	3.0	3.7	112.8	6.0	2.1	2.7
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.2	0.3	0.4 L	0.8	1.4	na	na	na	3.5	na	1.2 L	na	1.9
Regions Financial Corporation	0.2	3.3	0.7	na	0.3	0.4	0.4	0.3	0.6	1.0	1.7	2.8	4.5	2.6	3.7	115.2	3.8	1.8	2.2
ACIMA Private Wealth	0.1 L	3.3	1.3 H	1.7 H	0.0 L	0.0 L	0.0 L	0.2 L	0.5	1.3	2.3	4.8 H	7.5 H	2.9	3.8	110.0	2.5	0.9 L	2.7
AIG	0.1 L	na	na	na	0.1	0.2	0.5	0.5	0.6	1.0	1.7	na	3.7	na	3.1	na	10.0	1.1	2.1
Bank of America	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	1.6	2.3
Barclays	0.1 L	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	1.8	1.7
BMO Capital Markets	0.1 L	3.3	0.4	na	0.2	0.3	0.4	0.5	0.8	1.1	1.7	na	na	na	2.9	113.1	4.6	1.7	1.9
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.5	na	2.7
Chan Economics	0.1 L	3.3	0.7	0.8	0.1	0.2	0.3	0.5	0.7	0.9	1.5	2.8	4.3	1.9	3.3	113.7	1.6	2.0	2.0
Chmura Economics & Analytics	0.1 L	3.2	0.8	0.2	0.1	0.1	0.2	0.4	0.7	1.2	1.8	2.7	na	na	3.4	na	4.3	2.0	2.2
Comerica Bank	0.1 L	3.2	0.4	na	0.1	0.2	0.3	0.4	0.6	0.8	1.4	na	na	na	3.1	na	4.5	1.8	2.2
DePrince & Assoc.	0.1 L	3.1 L	0.6	0.4	0.1	0.2	0.3	0.3	0.4 L	0.9	1.4	2.9	4.0	2.5	2.9	110.9	5.8	1.6	1.7
Fannie Mae	0.1 L	3.3	na	na	0.3	0.3	0.3	0.4	0.6	0.8	1.3	na	na	na	2.9	na	5.0	1.1	2.5
Georgia State University	0.1 L	3.3	na	na	0.2	0.2	0.3	0.4	0.9	1.4	2.1	4.4	6.0	na	3.8	na	6.5	2.3	2.4
GLC Financial Economics	0.1 L	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.2 L	2.5	3.8	2.6	3.6	110.8	9.7	1.9	2.4
Goldman Sachs & Co.	0.1 L	na	0.5	na	0.3	na	na	na	na	1.0	na	na	na	na	2.9	na	6.0	1.4	2.1
Grant Thornton/Diane Swonk	0.1 L	3.3	0.3 L	0.2	0.1	0.2	0.6	0.5	0.6	0.9	1.7	2.2 L	4.1	na	2.9	na	12.3 H	1.1	1.9
ING	0.1 L	na	na	na	na	na	na	na	0.6	0.9	1.0	1.7	na	na	na	na	5.0	na	na
Loomis, Sayles & Company	0.1 L	3.3	0.3 L	0.2	0.1	0.1	0.2	0.4	0.6	1.1	1.6	2.2 L	3.0 L	2.2	2.8	113.4	8.7	1.2	1.7
MacroFin Analytics & Rutgers Bus School	0.1 L	3.3	1.1	0.4	0.2	0.2	0.3	0.3	0.4 L	0.7 L	1.3	2.8	4.0	3.2	3.4	117.0 H	4.0	1.8	2.0
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2	0.6	0.1 L	0.3	0.4	0.6	0.8	1.0	1.2	2.3	2.6	3.7	2.3	3.2	na	2.7	1.8	3.1
MUFG Union Bank	0.1 L	3.3	0.3 L	na	0.1	0.1	0.2	0.3	0.5	0.7 L	1.2 L	2.5	4.0	2.6	3.1	115.0	2.5	1.5	2.6
Naroff Economic Advisors	0.1 L	3.3	1.2	1.7 H	0.2	0.3	0.5	0.6	0.8	1.2	1.8	2.8	3.9	2.9	3.9	112.0	2.3	1.7	1.7
NatWest Markets	0.1 L	3.2	0.3 L	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.7	2.9	106.0 L	3.4	2.3	2.2
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.6	0.9	1.2	na	na	na	na	na	na	6.3	1.7	0.3 L
Oxford Economics	0.1 L	3.3	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	2.3	na	na	3.8	na	12.0	2.1	1.9
PNC Financial Services Corp.	0.1 L	3.3	0.3 L	na	0.1	0.2	0.2	0.2 L	0.5	0.9	1.6	na	4.2	1.1 L	3.0	na	5.6	1.8	2.2
S&P Global	0.1 L	na	na	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	4.3	5.6 H	4.5 H
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.6	0.7	0.8	1.4	na	na	na	na	na	1.5	1.2	1.5
Swiss Re	0.1 L	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7 L	na	2.1	1.7	2.0
The Northern Trust Company	0.1 L	3.3	0.5	0.3	0.2	0.3	0.3	0.5	0.8	1.1	1.6	2.7	3.6	3.4	2.8	109.3	2.4	1.6	1.5
Wells Fargo	0.1 L	3.3	0.3 L	0.1 L	0.2	0.2	0.3	0.6	0.9	1.1	1.7	2.4	4.3	2.8	3.0	na	2.5	1.9	2.0
May Consensus	**0.2**	**3.3**	**0.6**	**0.5**	**0.2**	**0.3**	**0.4**	**0.5**	**0.7**	**1.1**	**1.7**	**2.9**	**4.2**	**2.6**	**3.3**	**112.5**	**4.8**	**1.9**	**2.1**
Top 10 Avg.	0.3	3.4	0.9	0.7	0.3	0.4	0.6	0.8	1.1	1.4	2.2	3.4	4.9	3.0	3.8	114.4	8.4	2.6	2.8
Bottom 10 Avg.	0.1	3.2	0.3	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.5	3.7	2.2	2.9	110.7	2.1	1.3	1.3
April Consensus	0.3	3.4	0.7	0.7	0.3	0.3	0.5	0.7	1.0	1.3	2.0	3.1	4.3	2.6	3.4	111.9	3.6	1.9	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	11	10	9	10	9	13	14	17	19	21	20	13	14	8	13	4	5	9	13
Same	25	17	10	8	18	11	10	12	13	13	10	4	4	3	8	6	10	16	12
Up	4	3	6	2	5	7	6	5	2	2	3	5	5	6	8	7	23	10	12
Diffusion Index	41%	38%	44%	30%	44%	40%	37%	32%	25%	24%	24%	32%	30%	44%	41%	59%	74%	51%	49%

Third Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term			Long-Term								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Adv Fgn Econ $ Index	Real GDP	GDP Price Index	Cons. Price Index
Amherst Pierpont Securities	1.1 H	4.2 H	1.6 H	1.2	1.1 H	1.3 H	1.8 H	2.0 H	2.4 H	2.8 H	3.4 H	4.3	5.5	4.0 H	4.7 H	116.0	3.1	2.4	2.8
Daiwa Capital Markets America	0.8	3.9	1.1	0.9	0.8	0.9	1.0	1.4	1.5	1.7	2.2	3.0	4.0	na	3.6	112.0	3.0	1.9	2.2
Moody's Capital Markets Group	0.6	3.8	1.0	0.7	0.6	0.7	0.7	0.8	1.0	1.3	1.7	2.7	3.6	2.7	3.1	115.9	2.7	1.6	1.2
Action Economics	0.4	3.5	0.8	0.5	0.4	0.4	0.4	0.5	0.8	1.0	1.6	3.1	4.2	3.0	3.7	112.7	na	na	na
Naroff Economic Advisors	0.4	3.5	1.5	1.9 H	0.4	0.6	0.8	0.9	1.1	1.4	2.1	3.1	4.3	3.1	4.1	111.0	2.1	1.7	1.8
Chan Economics	0.3	3.5	0.8	0.9	0.3	0.4	0.5	0.7	0.9	1.1	1.7	3.0	4.5	2.1	3.5	113.9	1.5 L	2.0	2.1
Chmura Economics & Analytics	0.3	3.4	0.7	0.3	0.2	0.3	0.4	0.5	0.9	1.3	1.9	2.7	na	na	3.4	na	3.0	1.7	1.7
ING	0.3	na	na	na	na	na	na	0.8	1.2	1.3	1.9	na	na	na	na	na	4.0	na	na
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.5	2.4	1.5
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.9	1.2	1.5	2.1	na	na	na	na	na	4.4	1.3	1.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5 L	0.8	1.5	2.8	3.8	1.5	3.3	108.0	3.0	2.0	2.2
DePrince & Assoc.	0.2	3.2 L	0.7	0.5	0.2	0.3	0.4	0.4	0.5 L	1.0	1.5	3.0	4.1	2.6	3.0	110.6	4.1	1.6	1.7
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.3	0.3	0.3	0.5 L	1.0	1.4	na	na	na	3.5	na	1.9	na	2.2
MacroFin Analytics & Rutgers Bus School	0.2	3.5	1.2	0.5	0.3	0.3	0.4	0.4	0.5 L	0.8	1.4	3.0	4.2	3.3	3.5	117.5 H	2.0	2.0	2.0
Oxford Economics	0.2	3.3	0.4	na	0.2	0.2	0.4	0.5	0.9	1.4	2.2	2.4	na	na	3.7	na	5.6	1.9	1.9
Regions Financial Corporation	0.2	3.3	0.7	na	0.3	0.4	0.5	0.4	0.7	1.1	1.8	3.0	4.8	2.7	3.8	115.9	3.4	1.6	2.0
Wells Fargo	0.2	3.3	0.3	0.2	0.2	0.2	0.3	0.6	0.9	1.1	1.7	2.4	4.3	2.9	3.1	na	2.2	1.7	2.0
ACIMA Private Wealth	0.1 L	3.3	1.3	1.7	0.0 L	0.0 L	0.0 L	0.2 L	0.5 L	1.5	2.5	4.8 H	7.3 H	2.9	3.7	110.0	3.0	0.8 L	1.3
AIG	0.1 L	na	na	na	0.1	0.2	0.5	0.5	0.7	1.1	1.8	na	3.7	na	3.0	na	4.0	1.1	2.0
Bank of America	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.9	1.9	2.3
Barclays	0.1 L	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	2.3	2.7
BMO Capital Markets	0.1 L	3.3	0.4	na	0.2	0.3	0.4	0.5	0.9	1.2	1.9	na	na	na	3.0	112.3	4.0	1.7	1.9
BNP Paribas Americas	0.1 L	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.9	na	2.6
Comerica Bank	0.1 L	3.2 L	0.4	na	0.1	0.2	0.3	0.4	0.6	0.8	1.4	na	na	na	3.0	na	4.0	2.3	3.6 H
Fannie Mae	0.1 L	3.3	na	na	0.3	0.3	0.4	0.4	0.6	0.8	1.3	na	na	na	2.9	na	3.3	1.0	1.5
Georgia State University	0.1 L	3.3	na	na	0.2	0.2	0.3	0.4	1.0	1.7	2.4	4.4	6.0	na	3.9	na	4.4	2.3	2.5
GLC Financial Economics	0.1 L	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5 L	0.7 L	1.0 L	2.1 L	3.3	2.4	3.5	109.9	5.5	2.0	2.4
Goldman Sachs & Co.	0.1 L	na	0.5	na	0.3	na	na	na	na	1.1	na	na	na	na	3.0	na	5.0	1.6	2.1
Grant Thornton/Diane Swonk	0.1 L	3.3	0.3	0.3	0.1	0.2	0.5	0.4	0.5 L	0.9	1.7	2.2	3.8	na	2.8	na	7.1	1.0	1.9
Loomis, Sayles & Company	0.1 L	3.3	0.2 L	0.2	0.1	0.1	0.2	0.4	0.7	1.2	1.6	2.2	3.0 L	2.2	2.8	113.3	4.2	1.4	1.9
Mizuho Research Institute	0.1 L	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1 L	3.2 L	0.7	0.1 L	0.4	0.5	0.7	0.9	1.2	1.4	2.5	2.6	3.7	2.4	3.3	na	7.6 H	1.8	3.5
MUFG Union Bank	0.1 L	3.3	0.3	na	0.1	0.1	0.2	0.3	0.5 L	0.7 L	1.2	2.5	4.0	2.5	3.1	114.0	2.5	1.5	2.3
NatWest Markets	0.1 L	3.2 L	0.3	0.2	0.1	0.2	0.3	0.4	0.5 L	1.1	1.7	2.8	3.8	2.5	2.9	105.0 L	3.4	1.9	2.1
Nomura Securities, Inc.	0.1 L	3.3	na	na	na	na	na	0.7	1.1	1.4	na	na	na	na	na	na	5.7	1.6	0.7 L
PNC Financial Services Corp.	0.1 L	3.3	0.3	na	0.1	0.2	0.2	0.2 L	0.6	1.0	1.6	na	4.3	1.2 L	3.0	na	4.7	2.5	2.7
S&P Global	0.1 L	na	na	na	0.2	0.2	0.3	0.5	1.0	1.5	2.2	na	na	na	3.6	na	2.0	5.1 H	3.5
Societe Generale	0.1 L	na	na	na	0.1	0.1	na	0.7	0.8	1.0	1.7	na	na	na	na	na	1.5 L	1.2	1.5
Swiss Re	0.1 L	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7 L	na	2.0	1.4	1.9
The Northern Trust Company	0.1 L	3.3	0.5	0.3	0.2	0.3	0.4	0.6	1.0	1.3	1.8	2.9	3.8	3.6	3.0	109.1	2.1	1.7	1.6
May Consensus	**0.2**	**3.4**	**0.7**	**0.6**	**0.3**	**0.3**	**0.4**	**0.6**	**0.8**	**1.2**	**1.8**	**3.0**	**4.3**	**2.6**	**3.3**	**112.2**	**3.6**	**1.8**	**2.1**
Top 10 Avg.	0.5	3.6	1.1	0.9	0.5	0.6	0.7	1.0	1.3	1.6	2.4	3.5	5.0	3.1	3.8	114.4	5.4	2.5	2.9
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.5	3.7	2.2	2.9	110.1	2.0	1.2	1.5
April Consensus	0.3	3.5	0.7	0.8	0.3	0.4	0.5	0.7	1.0	1.4	2.0	3.1	4.3	2.6	3.5	111.7	3.1	1.8	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	11	10	10	9	12	11	14	17	19	21	20	14	13	7	14	3	8	13	11
Same	23	15	10	7	14	13	8	10	10	11	5	5	5	5	8	7	8	11	15
Up	6	5	5	4	6	7	8	7	5	4	8	3	5	5	7	7	21	10	10
Diffusion Index	44%	42%	40%	38%	41%	44%	40%	35%	29%	26%	32%	25%	33%	44%	38%	62%	68%	46%	49%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.13	0.13	0.13	--	--	--	--	--	--
BMO Capital Markets	0.13	0.13	0.13	0.60	0.75	1.05	116.2	115.2	113.4
IHSMarkit	--	--	--	0.47	0.49	0.91	--	--	--
ING Financial Markets	0.13	0.13	0.13	0.50	0.75	1.00	115.2	111.2	107.8
Mizuho Research Institute	--	--	--	0.70	0.75	0.80	--	--	--
Moody's Analytics	0.23	0.06	0.08	0.43	0.63	0.99	--	--	--
Moody's Capital Markets	0.13	0.13	0.13	0.72	0.82	1.05	114.7	115.3	115.7
Northern Trust	0.13	0.13	0.13	0.75	0.75	1.10	112.5	111.0	109.5
Oxford Economics	0.13	0.13	0.13	0.72	0.95	1.27	--	--	--
S&P Global	0.13	0.13	0.13	0.70	1.00	1.34	--	--	--
Scotiabank	0.13	0.13	0.13	0.85	1.05	1.30	--	--	--
Wells Fargo	0.13	0.13	0.13	1.00	1.15	1.30	114.7	115.2	114.3
May Consensus	**0.14**	**0.12**	**0.13**	**0.68**	**0.83**	**1.10**	**114.7**	**113.6**	**112.1**
High	0.23	0.13	0.13	1.00	1.15	1.34	116.2	115.3	115.7
Low	0.13	0.06	0.08	0.43	0.49	0.80	112.5	111.0	107.8
Last Months Avg.	0.15	0.12	0.19	0.84	1.01	1.28	115.5	114.7	113.4

Japan

Blue Chip Forecasters	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.10	-0.10	-0.10	-0.10	-0.05	0.00	107.0	104.0	105.0
BMO Capital Markets	-0.05	-0.05	-0.05	-0.05	-0.05	-0.10	110.0	111.0	112.0
IHSMarkit	--	--	--	--	--	--	108.6	109.9	110.9
ING Financial Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	118.0	115.0	120.0
Mizuho Research Institute	--	--	--	-0.05	0.00	0.00	107.0	108.0	109.0
Moody's Analytics	-0.10	-0.10	-0.10	-0.48	-0.49	-0.55	112.3	115.0	116.9
Moody's Capital Markets	-0.10	-0.10	-0.10	-0.05	-0.03	0.00	107.7	108.0	108.2
Nomura Securities	--	--	--	--	--	--	106.0	108.0	110.0
Northern Trust	-0.10	-0.10	-0.10	-0.05	-0.10	-0.05	109.0	108.0	108.0
Oxford Economics	-0.05	-0.06	-0.05	-0.11	-0.11	-0.10	107.0	106.5	106.0
S&P Global	-0.05	-0.06	-0.07	-0.16	-0.20	-0.06	105.0	106.0	105.8
Scotiabank	-0.10	-0.10	-0.10	--	--	--	107.0	107.0	106.0
Wells Fargo	-0.10	-0.10	-0.10	0.00	0.05	0.15	107.0	106.0	104.0
May Consensus	**-0.09**	**-0.09**	**-0.09**	**-0.11**	**-0.10**	**-0.07**	**108.6**	**108.6**	**109.4**
High	-0.05	-0.05	-0.05	0.00	0.05	0.15	118.0	115.0	120.0
Low	-0.10	-0.10	-0.10	-0.48	-0.49	-0.55	105.0	104.0	104.0
Last Months Avg.	-0.09	-0.09	-0.09	-0.12	-0.12	-0.09	106.6	106.8	107.9

United Kingdom

Blue Chip Forecasters	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	0.10	0.35	0.40	0.50	1.16	1.15	1.13
BMO Capital Markets	0.10	0.10	0.10	0.35	0.25	0.55	1.23	1.23	1.25
IHSMarkit	--	--	--	--	--	--	1.20	1.20	1.21
ING Financial Markets	0.10	0.10	0.10	0.20	0.40	0.80	1.26	1.31	1.39
Moody's Analytics	0.10	0.01	0.01	0.05	-0.09	0.04	1.29	1.31	1.40
Moody's Capital Markets	0.10	0.10	0.10	0.30	0.35	0.50	1.23	1.22	1.22
Nomura Securities	--	--	--	--	--	--	1.16	1.20	1.29
Northern Trust	0.10	0.10	0.10	0.35	0.30	0.40	1.25	1.27	1.30
Oxford Economics	0.10	0.10	0.10	0.42	0.49	0.70	1.24	1.25	1.27
S&P Global	0.10	0.10	0.10	0.43	0.44	0.63	1.23	1.25	1.31
Scotiabank	0.10	0.10	0.10	--	--	--	1.27	1.28	1.30
Wells Fargo	0.10	0.10	0.10	0.45	0.55	0.75	1.23	1.23	1.26
May Consensus	**0.10**	**0.09**	**0.09**	**0.32**	**0.34**	**0.54**	**1.23**	**1.24**	**1.28**
High	0.10	0.10	0.10	0.45	0.55	0.80	1.29	1.31	1.40
Low	0.10	0.01	0.01	0.05	-0.09	0.04	1.16	1.15	1.13
Last Months Avg.	0.10	0.09	0.09	0.45	0.44	0.57	1.21	1.22	1.26

Switzerland

Blue Chip Forecasters	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.98	0.99	1.00
ING Financial Markets	-0.75	-0.75	-0.75	-0.45	-0.35	-0.30	0.94	0.93	0.92
Moody's Analytics	-0.75	-0.75	-0.75	-1.09	-1.00	-0.95	0.93	0.91	0.86
Moody's Capital Markets	-0.75	-0.75	-0.75	-0.50	-0.48	-0.45	0.98	0.98	0.99
Nomura Securities	--	--	--	--	--	--	0.96	0.95	0.95
Northern Trust	-0.75	-0.75	-0.75	-0.50	-0.50	-0.40	0.96	0.97	0.99
Oxford Economics	-0.75	-0.75	-0.75	-0.37	-0.33	-0.23	0.97	1.00	1.02
S&P Global	-0.75	-0.75	-0.75	-0.28	-0.39	-0.47	0.97	0.97	0.97
Scotiabank	--	--	--	--	--	--	0.95	0.94	0.93
Wells Fargo	--	--	--	--	--	--	0.98	0.98	0.94
May Consensus	**-0.75**	**-0.75**	**-0.75**	**-0.53**	**-0.51**	**-0.47**	**0.96**	**0.96**	**0.96**
High	-0.75	-0.75	-0.75	-0.28	-0.33	-0.23	0.98	1.00	1.02
Low	-0.75	-0.75	-0.75	-1.09	-1.00	-0.95	0.93	0.91	0.86
Last Months Avg.	-0.75	-0.75	-0.75	-0.56	-0.55	-0.47	0.96	0.97	0.97

Canada

Blue Chip Forecasters	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
BMO Capital Markets	0.25	0.25	0.25	0.60	0.75	1.05	1.44	1.42	1.38
IHSMarkit	--	--	--	--	--	--	1.44	1.42	1.39
ING Financial Markets	0.25	0.25	0.25	0.70	1.00	1.50	1.45	1.38	1.28
Moody's Analytics	0.25	0.25	0.25	0.50	0.59	0.95	1.43	1.41	1.34
Moody's Capital Markets	0.25	0.25	0.25	0.60	0.66	0.85	1.41	1.42	1.43
Nomura Securities	--	--	--	--	--	--	1.45	1.40	1.37
Northern Trust	0.25	0.25	0.25	0.60	0.50	0.60	1.39	1.36	1.33
Oxford Economics	0.25	0.25	0.25	0.59	0.65	0.84	1.51	1.51	1.50
S&P Global	0.25	0.25	0.25	0.76	1.04	1.53	1.45	1.40	1.38
Scotiabank	0.25	0.25	0.25	0.90	1.00	1.30	1.39	1.38	1.35
Wells Fargo	0.25	0.25	0.25	0.90	1.00	1.25	1.43	1.43	1.41
May Consensus	**0.25**	**0.25**	**0.25**	**0.68**	**0.80**	**1.10**	**1.44**	**1.41**	**1.38**
High	0.25	0.25	0.25	0.90	1.04	1.53	1.51	1.51	1.50
Low	0.25	0.25	0.25	0.50	0.50	0.60	1.39	1.36	1.28
Last Months Avg.	0.25	0.25	0.25	0.69	0.79	1.03	1.46	1.43	1.40

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.61	0.61	0.63
ING Financial Markets	0.25	0.25	0.25	0.75	0.70	1.20	0.58	0.63	0.67
Moody's Analytics	0.25	0.25	0.25	0.26	0.01	0.06	0.63	0.63	0.67
Moody's Capital Markets	0.25	0.25	0.25	0.95	1.00	1.15	0.64	0.65	0.65
Nomura Securities	--	--	--	--	--	--	0.62	0.61	0.63
Northern Trust	0.25	0.25	0.25	0.95	0.90	1.00	0.65	0.66	0.67
Oxford Economics	0.25	0.25	0.25	0.85	0.85	0.85	0.62	0.62	0.65
S&P Global	0.25	0.25	0.25	0.34	0.66	1.04	0.63	0.65	0.66
Scotiabank	0.25	0.25	0.25	--	--	--	0.62	0.63	0.66
Wells Fargo	--	--	--	--	--	--	0.61	0.61	0.63
May Consensus	**0.25**	**0.25**	**0.25**	**0.68**	**0.69**	**0.88**	**0.62**	**0.63**	**0.65**
High	0.25	0.25	0.25	0.95	1.00	1.20	0.65	0.66	0.67
Low	0.25	0.25	0.25	0.26	0.01	0.06	0.58	0.61	0.63
Last Months Avg.	0.25	0.25	0.25	0.70	0.63	0.70	0.59	0.60	0.62

Euro area

Blue Chip Forecasters	Main Refinancing Rate			US$ per Euro		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.00	0.00	0.00	1.08	1.06	1.02
BMO Capital Markets	0.00	0.00	0.00	1.06	1.07	1.10
IHSMarkit	--	--	--	1.09	1.09	1.08
ING Financial Markets	0.00	0.00	0.00	1.12	1.15	1.18
Moody's Analytics	0.00	0.00	0.00	1.13	1.16	1.23
Moody's Capital Markets	0.00	0.00	0.00	1.07	1.06	1.05
Nomura Securities	--	--	--	1.07	1.09	1.12
Northern Trust	0.00	0.00	0.00	1.11	1.15	1.16
Oxford Economics	0.00	0.00	0.00	1.09	1.08	1.08
S&P Global	0.00	0.00	0.00	1.08	1.09	1.12
Scotiabank	0.00	0.00	0.00	1.10	1.12	1.14
Wells Fargo	-0.50	-0.50	-0.50	1.07	1.07	1.12
May Consensus	**-0.05**	**-0.05**	**-0.05**	**1.09**	**1.10**	**1.12**
High	0.00	0.00	0.00	1.13	1.16	1.23
Low	-0.50	-0.50	-0.50	1.06	1.06	1.02
Last Months Avg.	-0.06	-0.06	-0.06	1.10	1.10	1.12

Blue Chip Forecasters	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.65	-0.60	-0.50	--	--	--	--	--	--	--	--	--
BMO Capital Markets	-0.40	-0.30	-0.05	--	--	--	--	--	--	--	--	--
ING Financial Markets	-0.50	-0.40	-0.25	-0.05	0.00	0.05	1.50	1.40	1.35	0.50	0.40	0.55
Moody's Analytics	-0.68	-0.52	-0.34	-0.03	0.01	0.09	2.46	2.02	1.76	0.93	0.87	0.71
Moody's Capital Markets	-0.40	-0.32	-0.25	0.12	0.18	0.20	1.88	1.92	1.98	0.98	1.02	1.05
Northern Trust	-0.40	-0.40	-0.30	0.00	0.00	0.10	1.90	1.80	1.70	0.90	0.80	0.70
Oxford Economics	-0.43	-0.34	-0.17	0.06	0.16	0.33	1.51	1.66	1.93	0.74	0.86	1.13
S&P Global	-0.37	-0.48	-0.50	0.08	-0.06	-0.10	1.58	1.62	1.40	0.73	0.62	0.40
Wells Fargo	-0.40	-0.30	-0.10	--	--	--	--	--	--	--	--	--
May Consensus	**-0.47**	**-0.41**	**-0.27**	**0.03**	**0.05**	**0.11**	**1.81**	**1.74**	**1.69**	**0.80**	**0.76**	**0.76**
High	-0.37	-0.30	-0.05	0.12	0.18	0.33	2.46	2.02	1.98	0.98	1.02	1.13
Low	-0.68	-0.60	-0.50	-0.05	-0.06	-0.10	1.50	1.40	1.35	0.50	0.40	0.40
Last Months Avg.	-0.42	-0.34	-0.23	0.05	0.09	0.18	1.65	1.58	1.61	0.67	0.66	0.72

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.62	-0.78	-0.92	-1.17
United Kingdom	-0.28	-0.35	-0.48	-0.56
Switzerland	-1.03	-1.21	-1.33	-1.57
Canada	-0.02	0.01	-0.03	0.00
Australia	0.28	0.01	-0.14	-0.22
Germany	-1.07	-1.15	-1.23	-1.37
France	-0.57	-0.65	-0.78	-0.99
Italy	1.24	1.13	0.91	0.59
Spain	0.41	0.12	-0.06	-0.34

Consensus Forecasts
Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.23	-0.23	-0.04	-0.21
United Kingdom	-0.03	-0.04	-0.03	-0.03
Switzerland	-0.88	-0.89	-0.87	-0.88
Canada	0.13	0.11	0.13	0.13
Australia	0.13	0.11	0.13	0.13
Euro area	-0.13	-0.19	-0.17	-0.18

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Small Businesses and Oil Market Shocked by COVID-19, but Don't Rush Reopening

We love tales of successful entrepreneurship. We admire tech titans who start by cobbling together computers in a parent's garage, researchers who spend years perfecting and then producing revolutionary medical therapies, and small people with big ideas who overcome serial failure to produce an overriding success. Their creativity, drive and dedication serve as an example for others to follow.

But small businesses are not only a source of inspiration. Small businesses are the growth drivers of modern economies. They are a vital source of innovation and employment, and they are fixtures within their communities. Unfortunately, small businesses have been placed at significant risk by the coronavirus. Governments around the world are racing to support them before they fail.

The definition of small-and-medium-sized enterprise (SME) has some local variation. The European Union (EU) defines a medium-size company as one with up to 250 workers, while the U.S. Small Business Administration (SBA) typically supports businesses of up to 500. According to the World Bank, SMEs account for the majority of businesses globally, representing over 90% of all firms and over 50% of employment worldwide.

In high income, Organization for Economic Cooperation and Development (OECD) countries, SMEs account for the vast majority of companies (99% of all firms), about 70% of employment and more than half of value added. SMEs in emerging markets (EMs) represent a little less than half of total employment and about one-third of gross domestic product (GDP). If one accounts for the large informal sector in countries like India, their importance is likely to be even greater than is reflected in formal statistics.

Entrepreneurship has long been vital to global economic policy. It represents a path to prosperity for those willing to work hard and serves as a source of constant economic renewal. An OECD survey shows that SMEs participate significantly in a range of innovative work: For example, SMEs account for about 20% of patents in biotechnology-related fields in Europe.

Recognizing the importance of the small business sector, countries around the world have established agencies to aid them. The U.S. SBA was created in 1953 to guarantee loans to SMEs. SMEs have been a focal point in shaping the EU's enterprise policy. And China has worked hard over the past few years to diversify away from large state-owned enterprises and encourage the formation of more fledgling firms.

But with over half of the world population now under some of lockdown, smaller bus are bearing the brunt of reductions in global demand. According to a survey of over 1,500 small firms in the United States, 51% of owners said they will be able to continue operations for less than three months in the current economic environment. A February survey of China's SMEs revealed that only one-third had enough cash to cover fixed expenses for a month. At a European level, about 90% of SMEs have experienced business losses of at least 50%.

Policymakers across the world are making unprecedented efforts to help SMEs stay in business and sustain their employment. Those measures include temporary tax relief, direct financial support, loan subsidies and moratoriums on debt repayments. Some prominent examples are:

- In the U.S., SBA's new Paycheck Protection Program will forgive loans if they are used to maintain payrolls. Its initial $349 billion of funding was consumed within two weeks, and this week's fresh tranche of $310 billion will meet high demand when it is released.

- Among European nations, France took the lead on SME funding, with French banks offering more state-backed loans than other countries in Europe. The Italian Banking Association agreed to a large-scale moratorium on debt repayments, including mortgages and repayments of small loans and revolving credit lines for businesses. The U.K. announced cash grants of £10,000 for eligible small businesses and up to £25,000 for SMEs in retail, hospitality and leisure; a 100% business tax holiday has been established for the next 12 months.

- The Reserve Bank of Australia has established a term funding facility of at least $50 billion for the banking system, including credit support to small- and medium-sized businesses.

- Asian economies including South Korea and Singapore are offering flexibility for repayments of existing loans. India increased the threshold for starting insolvency proceedings against SMEs in default by a factor of 100.

Even though many small firms might manage their way through this crisis without permanent scars, the hurdles are only going to increase in the aftermath of the Great Lockdown. Access to credit has always been a challenge in this sector; the crisis could do damage to the banks and investment pools that have traditionally arranged financing for younger companies. International capital has grown as a resource, but advancing protectionism could restrict inbound investment. In one recent example, India amended its foreign direct investment rules to halt the acquisition of Indian businesses by neighboring countries, with an eye on China. Australia and the European Union are considering similar moves.

Though the current support measures might help alleviate some pain, they are likely to fall short of providing relief to all who have been affected by this unprecedented crisis. Widespread bankruptcies are a potential byproduct of prolonged virus containment measures. Considering the World Bank's estimate that 600 million jobs will be needed in the next decade to absorb the growing global workforce, governments will have to ensure SMEs not only survive but are ready to thrive when growth resumes. Substantial assistance is on offer to SMEs, but it is also vital to ensure that the support schemes are easily accessible and topped up where necessary.

Every business leader can share war stories of times when they faced difficult circumstances, only to survive and emerge even stronger. Today's circumstances, though, may fall beyond the capacity of even the most intrepid entrepreneurs to adapt and overcome. Policy will need to raise the odds that small businesses survive; for their sake, and for ours.

Losing Energy. If these were normal times, the biggest story in the global economy would be the collapse in oil prices. Crude has been in retreat for six weeks; conditions reached a strange nadir this week when some spot and futures prices for a barrel of oil went below zero. That extreme resulted from technical factors in the energy markets. But fundamentally, there is a glut of petroleum accumulating, and it may take a long time for it to dissipate.

About 70% of fuel derived from oil is used for transportation: road, rail, sea and air. When COVID19 first emerged, factory shutdowns in China

interrupted supply chains and left rail cars and tankers idle. As the virus spread to other countries, social distancing measures led to tens of thousands of cancelled flights, a steep decline in car traffic, and further impairment of shipping. Restrictions on movement are still spreading and strengthening, and will likely take some time to relax. In all, petroleum demand has collapsed by about 20% from former levels.

On the supply side, global oil production has remained strong. Failure to agree on output restrictions led to a damaging battle between Saudi Arabia and Russia. The oil market was almost literally being flooded with crude, to the point where storage began to reach capacity in some places. If the intent of the Saudis was to punish overproducers, or to do damage to competitors, the effort has been a success.

In a landmark arrangement, the United States joined an agreement with the Organization of Petroleum Exporting Countries (OPEC) and Russia in a plan to reduce production. (The prospect of the U.S. collaborating with OPEC to reduce oil supply would have been anathema twenty years ago.) The new guidelines went into effect this week, but will not be nearly enough to bring prices back to their levels of early this year.

Prices are too low to support new development, so companies that supply equipment and engineering expertise will see their business dwindle. Existing wells are being closed off at a rapid pace, because the cost of extraction is far above the prevailing market price. This has been especially harsh for U.S. and Canadian producers. Some smaller energy companies have borrowed substantial sums through bond markets; some analysts are expecting default rates on those issues to approach 20% by the end of this year.

The American shale industry has appealed for federal relief, noting the strategic importance of energy independence. But other industries are at the head of the line. There are also those who note that some oil producers (and the investors who finance them) inherently take risks that the public should not have to backstop.

In the U.S., energy-producing states are going to see an extra measure of unemployment and additional declines in tax revenue. On a broader scale, energy-producing countries will feel a pinch if oil prices remain low. For countries that are heavily dependent on petroleum proceeds, significant holes will appear in their national budgets. Some will fill these holes by drawing down their financial reserves; those without reserves will struggle to sustain public spending and social stability.

In normal times, cheap fuel would be a boon to consumers and importers. But because driving and flying have been so severely curtailed, the benefit to households will be limited. If there is any consolation at all, it is that air quality in many parts of the world has improved, at least temporarily. Many forecasters are still predicting oil prices to return to the $50 range in the next year or so. That outlook is predicated on the assumption that economic conditions will normalize at a reasonable pace, which is not at all certain. The global energy industry, and the communities that depend on it, are facing a very difficult interval ahead.

Argumentum ad Absurdum. Tradeoffs are central to economics: Debt vs. savings, free markets vs. regulations, risks vs. rewards. We relish spirited debate around these balancing acts. Keep us talking long enough, and we may argue both sides of an issue. But sometimes, a clear answer emerges.

We think this applies to the debate over the post-quarantine recovery. A reader of the situation may conclude that communities are fighting with epidemiologists over when to lift economic restrictions. If only those meddling doctors would stand down, some say the economy would bounce back. We disagree.

A return to robust economic activity requires a populace that feels safe to leave their homes, go to businesses, earn income and spend it. Rushing a return to business-as-usual too soon could lead to a second wave of infections, which could be even more commercially and psychologically harmful than the current outbreak. And reopening businesses does not guarantee a return to business-as-usual, amid lingering public concern that crowded areas may be unsafe for some time to come.

The desire to reopen is understandable. Our incomes are down, our jobs and businesses are at risk, and frankly, we're bored. Quarantine measures reduce the spread of infections, but paradoxically, fewer infections can make us think the risk was overstated. Officials in Japan and Singapore found themselves fighting a second wave of infections after initial restrictions mitigated the risk and were then relaxed. We also take heed from the 1918-1920 influenza pandemic: regions that practiced aggressive social distancing saw less severe outbreaks and greater economic activity when the disease subsided.

Today's Great Lockdown is a circumstance we have no choice but to accept. This is a public health crisis, and health experts must determine the appropriate timing and pace of resuming activity. In the long run, following their instructions will likely lead to the best economic outcomes.

Carl R. Tannenbaum, Ryan James Boyle, Vaibhav Tandon (Northern Trust)

The Decline in Economic Activity is Breathtaking.

The economic numbers are coming in even worse than most economists expected. We really cannot wrap our minds around these enormous levels of changes, so it is hard to forecast the total collapse that we are starting to see. And the April numbers, which will reflect a whole month, are likely to be a lot worse.

Which brings us to the equity markets. The spread of the virus may be easing, at least we hope. New York looks like it is near or at the peak, but other areas are starting to heat up. Every state is now involved. Starting to open the economy in two weeks (May 1st) is hardly likely and when the economy does start to open, it is not going to happen quickly or easily. Yet investors have been exuberant the last three weeks. Is it rational or irrational? Where is Alan Greenspan when we need him? First quarter earnings are just starting to come in and for most firms they are gruesome. And that was with less than one month of a shutdown. What happens when we have two or even three months of restricted activity in a quarter followed by a slow, rolling reopening? It is hard to comprehend why businesses would invest in this type of economy. Businesses may start opening, but which ones? Without wide scale testing capacity, can we really open retail establishments that require social contact? The rest of the world is also going to slowly reopen and who knows when that will happen. And state and local governments are already starting to downsize as tax revenues are crashing. It is one thing to say that the government and the Fed are pouring trillions into the economy, but it is another to say that demand will recover to anywhere close to what it had been in February. And if it doesn't, firms will not see demand raise enough to keep the government funded workers, so layoffs and business closings could resume. Households will have used up some of the money they were given and if they don't have jobs (the unemployment rate could still be double-digits in July), spending will fade. And that could trigger a significant increase in loan losses and pressure on financial institutions. That is the prospect for the summer/fall economy. And what if the reopening has a set back due to a resurgence in parts of the country, even if those relapses are minor? So, where are the profits going to come from? I am just an economist, but I simply don't see what investors are seeing and to be honest, what other economists are saying is going to happen. I focus on the underlying factors that will drive future economic growth and earnings and while we will see an initial upturn once the economy reopens, the strength and length of that recovery is not clear at all.

Joel Naroff (Naroff Economics)

Special Questions:

1. a. Where do you see the federal funds rate at year-end 2020? 0.166% at year-end 2021? 0.305%

   b. How large do you estimate the Fed's balance sheet at year-end 2020? 8,611 bil$ at year-end 2021? 9,033 bil$

2. a. To date roughly $2.7 trillion of COVID related federal aid is in the pipeline. Do you believe this is enough?

Yes	No
9%	91%

   b. If not, how much more aid do you estimate will be needed? 1.4 tril$

   c. How large do you see the budget deficit in FY 2020? 3,315 bil$ FY 2021? 2,234 bil$

3. With 22 million people filing for unemployment insurance and an oil contract selling at a negative price, the economy is acting pretty weak.

   a. How long do you believe this evident recession will last? 5.8 months

   b. What month would show the weakest activity?

Mar 2020	Apr 2020	May 2020	Jun 2020	Later
3%	76%	16%	3%	3%

   c. What do you think will be the peak monthly unemployment rate for the U.S. in 2020? 17.5 %

   d. When would that be?

Apr	May	Jun	Jul	Oct	Nov
24%	49%	12%	6%	3%	6%

4. a. By the end of what month do you forecast mandated social distancing measures to be lifted for a majority of the population?

	May	Jun	Jul	Aug	Sep	Oct or later
Strict (stay at home orders)	41%	47%	6%	0%	3%	3%
Moderate (opening socially distant venues)	6%	44%	25%	19%	6%	0%
Relaxed (opening of all venues, non-essential travel, with social distancing recommendations)	0%	10%	0%	13%	16%	61%

   b. After mandated social distancing measures are relaxed, will there be a share of the population that chooses to socially distance and for how long?

	% of Population	Months
Strict (choose to stay home)	16%	7.7
Moderate (limit activity to minimize unnecessary contact)	30%	7.2
Relaxed (engage in normal everyday activities while trying to remain physically distant)	48%	7.6

5. In Q1 2020, the Covid-19 triggered massive capital outflows from Emerging Markets. The G-20 called for a suspension of debt service for the world's poorest countries from May to the end of 2020.

   a. Do you think the timeline will need to be extended?

Yes	No
93%	7%

   b. Do you think the suspension will need to be broadened to middle-income Emerging Market countries?

Yes	No
46%	54%

Databank:

2020 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	-0.4	-8.4	....	....	....	....	....	....	....	....	....
Auto & Light Truck Sales (b)	16.91	16.74	11.37	....	....	....	....	....	....	....	....	....
Personal Income (a, current $)	0.6	0.6	....	....	....	....	....	....	....	....	....	....
Personal Consumption (a, current $)	0.2	0.2	....	....	....	....	....	....	....	....	....	....
Consumer Credit (e)	3.5	6.4	....	....	....	....	....	....	....	....	....	....
Consumer Sentiment (U. of Mich.)	99.8	101.0	89.1	71.8	....	....	....	....	....	....	....	....
Household Employment (c)	-89	45	-2987	....	....	....	....	....	....	....	....	....
Nonfarm Payroll Employment (c)	214	275	-701	....	....	....	....	....	....	....	....	....
Unemployment Rate (%)	3.6	3.5	4.4	....	....	....	....	....	....	....	....	....
Average Hourly Earnings (All, cur. $)	28.43	28.51	28.62	....	....	....	....	....	....	....	....	....
Average Workweek (All, hrs.)	34.3	34.4	34.2	....	....	....	....	....	....	....	....	....
Industrial Production (d)	-0.9	0.0	-5.5	....	....	....	....	....	....	....	....	....
Capacity Utilization (%)	76.7	77.0	72.7	....	....	....	....	....	....	....	....	....
ISM Manufacturing Index (g)	50.9	50.1	49.1	....	....	....	....	....	....	....	....	....
ISM Nonmanufacturing Index (g)	55.5	57.3	52.5	....	....	....	....	....	....	....	....	....
Housing Starts (b)	1.619	1.564	1.216	....	....	....	....	....	....	....	....	....
Housing Permits (b)	1.550	1.452	1.350	....	....	....	....	....	....	....	....	....
New Home Sales (1-family) (h)	777	741	627	....	....	....	....	....	....	....	....	....
Construction Expenditures (a)	2.8	-1.3	....	....	....	....	....	....	....	....	....	....
Consumer Price Index (nsa, d)	2.5	2.3	1.5	....	....	....	....	....	....	....	....	....
CPI ex. Food and Energy (nsa, d)	2.3	2.4	2.1	....	....	....	....	....	....	....	....	....
Producer Price Index (nsa, d)	2.1	1.3	0.7	....	....	....	....	....	....	....	....	....
Durable Goods Orders (a)	0.1	1.1	-14.4	....	....	....	....	....	....	....	....	....
Leading Economic Indicators (a)	0.4	-0.2	-6.7	....	....	....	....	....	....	....	....	....
Balance of Trade & Services (f)	-45.5	-39.9	....	....	....	....	....	....	....	....	....	....
Federal Funds Rate (%)	1.55	1.58	0.65	....	....	....	....	....	....	....	....	....
3-Mo. Treasury Bill Rate (%)	1.55	1.54	0.30	....	....	....	....	....	....	....	....	....
10-Year Treasury Note Yield (%)	1.76	1.50	0.87	....	....	....	....	....	....	....	....	....

2019 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.5	-0.1	1.6	0.5	0.4	0.4	0.6	0.4	-0.4	0.5	0.0	0.1
Auto & Light Truck Sales (b)	16.71	16.52	17.26	16.48	17.39	17.18	16.88	16.97	17.15	16.52	16.99	16.65
Personal Income (a, current $)	0.3	0.6	0.4	0.3	0.2	0.4	0.0	0.4	0.2	0.1	0.5	0.2
Personal Consumption (a, current $)	0.6	-0.1	1.0	0.7	0.4	0.3	0.5	0.3	0.2	0.3	0.3	0.4
Consumer Credit (e)	5.2	4.8	3.6	5.1	4.3	3.5	6.7	4.5	3.1	3.9	2.1	6.0
Consumer Sentiment (U. of Mich.)	91.2	93.8	98.4	97.2	100.0	98.2	98.4	89.8	93.2	95.5	96.8	99.3
Household Employment (h)	-198	239	-125	-45	148	304	198	549	403	246	-8	267
Nonfarm Payroll Employment (c)	269	1	147	210	85	182	194	207	208	185	261	184
Unemployment Rate (%)	4.0	3.8	3.8	3.6	3.6	3.7	3.7	3.7	3.5	3.6	3.5	3.5
Average Hourly Earnings (All, cur. $)	27.58	27.69	27.76	27.81	27.87	27.96	28.05	28.16	28.16	28.24	28.34	28.37
Average Workweek (All, hrs.)	34.5	34.4	34.5	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.3	34.3
Industrial Production (d)	3.6	2.7	2.3	0.7	1.7	1.0	0.4	0.3	-0.2	-0.8	-0.4	-0.8
Capacity Utilization (%)	79.0	78.5	78.4	77.8	77.8	77.7	77.4	77.8	77.4	77.0	77.6	77.1
ISM Manufacturing Index (g)	55.5	54.1	54.6	53.4	52.3	51.6	51.3	48.8	48.2	48.5	48.1	47.8
ISM Nonmanufacturing Index (g)	56.0	58.5	56.3	55.7	56.3	55.4	54.8	56.0	53.5	54.4	53.9	54.9
Housing Starts (b)	1.291	1.149	1.199	1.270	1.264	1.233	1.204	1.375	1.266	1.340	1.381	1.601
Housing Permits (b)	1.316	1.287	1.288	1.290	1.299	1.232	1.317	1.425	1.391	1.461	1.474	1.420
New Home Sales (1-family) (h)	644	669	693	656	598	729	660	708	725	707	700	723
Construction Expenditures (a)	1.4	0.5	0.8	0.6	-0.7	-0.9	0.5	1.1	0.7	0.4	1.6	0.4
Consumer Price Index (nsa, d)	1.6	1.5	1.9	2.0	1.8	1.6	1.8	1.7	1.7	1.8	2.1	2.3
CPI ex. Food and Energy (nsa, d)	2.2	2.1	2.0	2.1	2.0	2.1	2.2	2.4	2.4	2.3	2.3	2.3
Producer Price Index (nsa, d)	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.3
Durable Goods Orders (a)	0.5	-2.6	1.7	-2.8	-2.3	1.8	2.1	0.2	-1.5	0.2	-3.1	2.8
Leading Economic Indicators (a)	0.0	0.2	0.2	0.1	0.0	0.0	0.4	-0.2	-0.2	-0.2	0.1	-0.1
Balance of Trade & Services (f)	-53.8	-51.3	-52.7	-51.3	-54.8	-54.3	-53.2	-53.9	-51.3	-47.4	-43.8	-48.6
Federal Funds Rate (%)	2.40	2.40	2.41	2.42	2.39	2.38	2.40	2.13	2.04	1.83	1.55	1.55
3-Mo. Treasury Bill Rate (%)	2.42	2.44	2.45	2.43	2.40	2.22	2.15	1.99	1.93	1.68	1.57	1.57
10-Year Treasury Note Yield (%)	2.71	2.68	2.57	2.53	2.40	2.07	2.06	1.63	1.70	1.71	1.81	1.86

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level; (h) thousands. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
May 4 Manufacturers' Shipments, Inventories & Orders (Mar) Senior Loan Officer Survey (Q2)	**5** Intl Trade/Supplement (Mar) ISM Nonmanufacturing (Apr) IHS Markit Services PMI(Apr)	**6** ADP Employment Report (Apr) Public Debt (Apr) EIA Crude Oil Stocks Mortgage Applications	**7** Productivity & Costs (Q1) Treasury Auction Allotments (Apr) Consumer Credit (Mar) Challenger Employment Report (Apr) Weekly Jobless Claims Weekly Money Supply	**8** Employment Situation (Apr) Wholesale Trade (Mar)
11 Kansas City Financial Stress Index (Apr)	**12** CPI (Apr) Monthly Treasury (Apr) NFIB (Apr) First Time Housing Affordability (Q1)	**13** Producer Prices (Apr) Transportation Services Index (Mar) EIA Crude Oil Stocks Mortgage Applications	**14** Import & Export Prices (Apr) Weekly Jobless Claims Weekly Money Supply	**15** Advance Retail Sales (Apr) IP & Capacity Utilization (Apr) MSIO Revisions**** (2019) Consumer Sentiment (May, Preliminary) MTIS (Mar) JOLTS (Mar) Empire State Mfg Survey (May) Professional Forecasters (Q2)
18 Business Leaders Survey(May) Home Builders (May) Kansas City Fed Labor Market Conditions Indicators (Apr)	**19** New Residential Construction (Apr) Retail E-Commerce Sales	**20** Advance Quarterly Services (Q1) CEW (Q4) EIA Crude Oil Stocks Mortgage Applications	**21** Existing Home Sales (Apr) Philadelphia Fed Mfg Business Outlook Survey (May) Existing Home Sales (Apr) Composite Indexes (Apr) Weekly Jobless Claims Weekly Money Supply	**22** Treasury Auction Allotments (May)
25 **MEMORIAL DAY**	**26** New Residential Sales (Apr) Final Building Permits (Apr) Chicago Fed National Activity Index (Apr) Philadelphia Fed Nonmfg Bus Outlook Survey (May) Texas Mfg Outlook (May) FHFA HPI (Q1 & Mar) Case Shiller HPI (Mar) Consumer Confidence (May)	**27** Richmond Fed Mfg & Service Sector Surveys (May) Texas Service Sector Outlook Survey (May) Philadelphia Fed Coincident Economic Activity Index Mortgage Applications	**28** GDP (Q1, 2nd Estimate) Advance Durable Goods (Apr) Kansas City Fed Manufacturing Survey (May) Weekly Jobless Claims Weekly Money Supply EIA Crude Oil Stocks	**29** Adv Trade & Inventories (Apr) Personal Income (Apr) Chicago PMI (May) Consumer Sentiment (May, Final)
June 1 ISM Manufacturing (May) Construction (Apr) NABE Outlook (Q2)	**2**	**3** ADP Employment Report(May) MSIO (Apr) ISM Nonmanufacturing (May) EIA Crude Oil Stocks Mortgage Applications	**4** Productivity & Costs (Q1) International Trade (Apr) Public Debt (May) Challenger Employment Report (May) Weekly Jobless Claims Weekly Money Supply	**5** Employment Situation (May) Consumer Credit (Apr)
8 QFR (Q1) Treasury Auction Allotments (May)	**9** JOLTS (Apr) Wholesale Trade (Apr) Manpower Survey (Q3) NFIB (May) Kansas City Financial Stress Index (May) FOMC Meeting	**10** CPI (May) Monthly Treasury (May) Kansas City Fed Labor Market Conditions Indicators (May) FOMC Meeting EIA Crude Oil Stocks Mortgage Applications	**11** PPI (May) QSS (Q1) Weekly Jobless Claims Weekly Money Supply	**12** Import & Export Prices (May) Consumer Sentiment (Jun, Preliminary) Livingston Survey (Jun)

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News Release

TRANSMISSION OF MATERIALS IN THIS RELEASE IS EMBARGOED UNTIL
8:30 A.M. (Eastern) Thursday, April 16, 2020

COVID-19 Impact
The COVID-19 virus continues to impact the number of initial claims and insured unemployment.

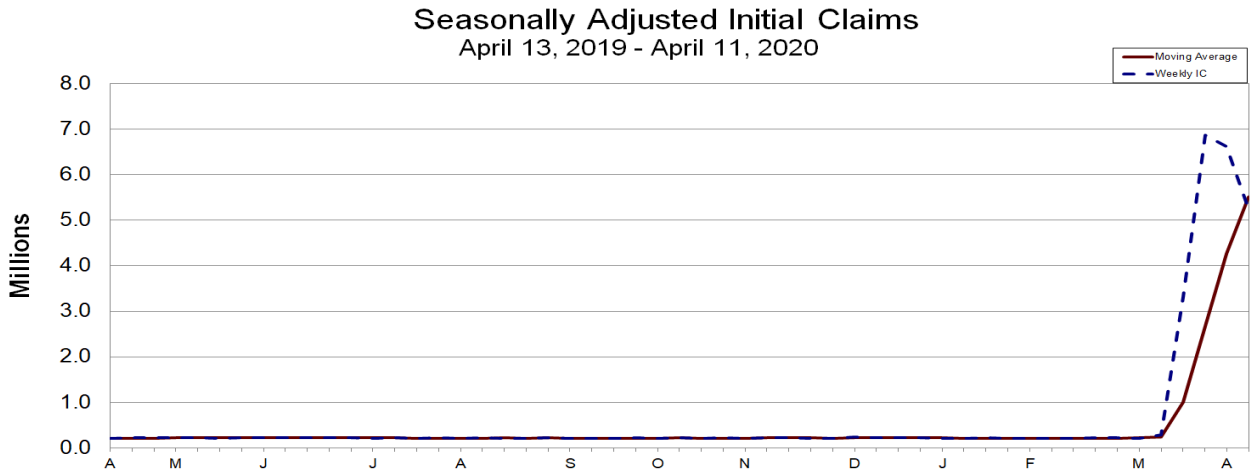
UNEMPLOYMENT INSURANCE WEEKLY CLAIMS

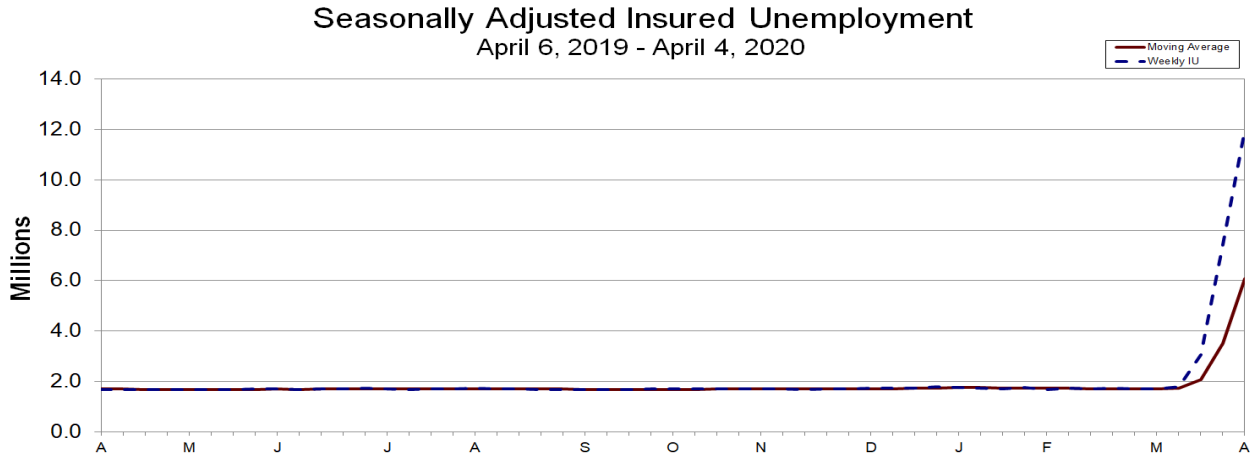
SEASONALLY ADJUSTED DATA

In the week ending April 11, the advance figure for seasonally adjusted **initial claims** was 5,245,000, a decrease of 1,370,000 from the previous week's revised level. The previous week's level was revised up by 9,000 from 6,606,000 to 6,615,000. The 4-week moving average was 5,508,500, an increase of 1,240,750 from the previous week's revised average. The previous week's average was revised up by 2,250 from 4,265,500 to 4,267,750.

The advance seasonally adjusted **insured unemployment rate** was 8.2 percent for the week ending April 4, an increase of 3.1 percentage points from the previous week's unrevised rate. This marks the highest level of the seasonally adjusted insured unemployment rate in the history of the seasonally adjusted series. The previous high was 7.0 percent in May of 1975.

The advance number for seasonally adjusted **insured unemployment** during the week ending April 4 was 11,976,000, an increase of 4,530,000 from the previous week's revised level. This marks the highest level of seasonally adjusted insured unemployment in the history of the seasonally adjusted series. The previous week's level was revised down by 9,000 from 7,455,000 to 7,446,000. The 4-week moving average was 6,066,250, an increase of 2,568,500 from the previous week's revised average. The previous week's average was revised down by 2,250 from 3,500,000 to 3,497,750.

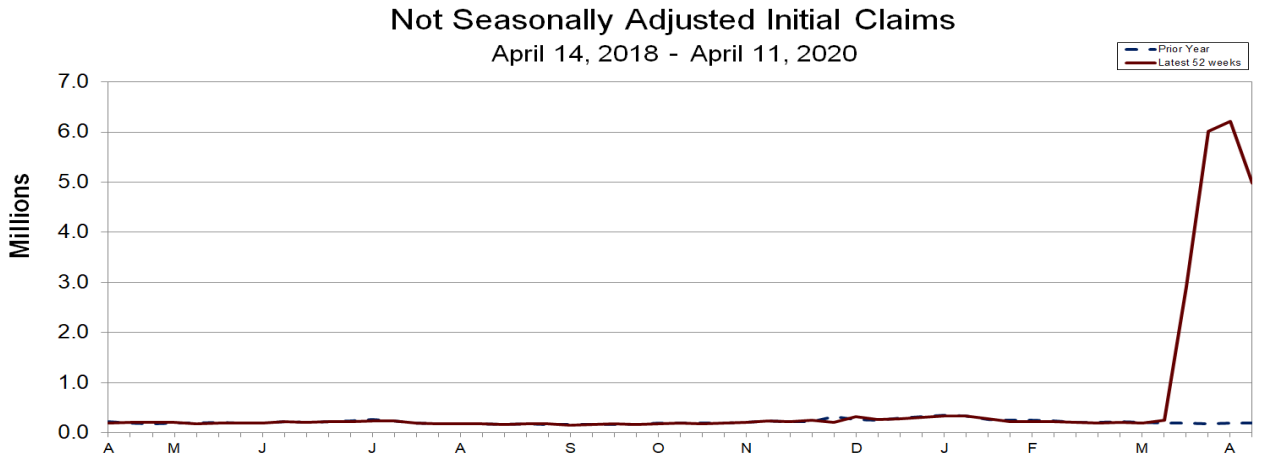


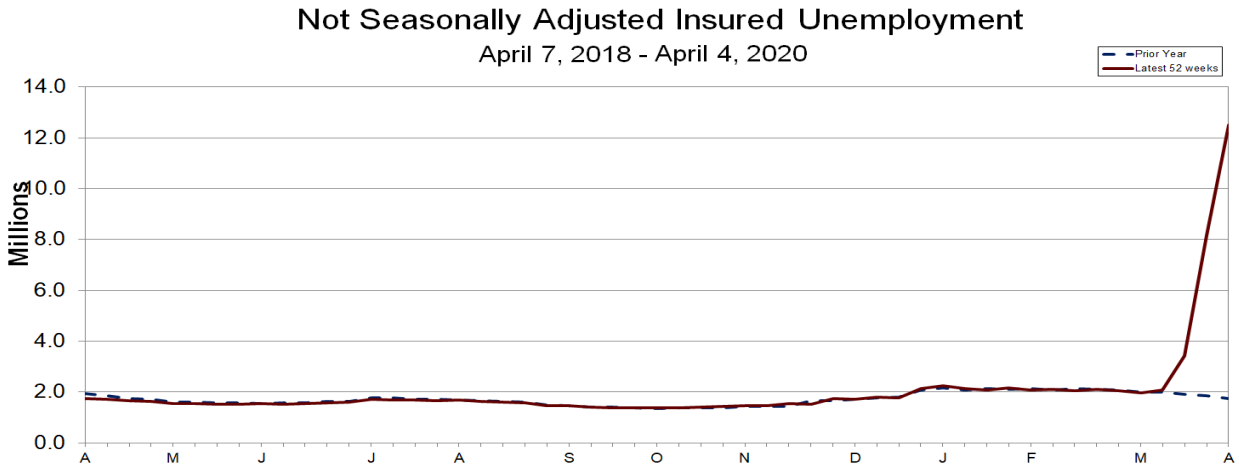


UNADJUSTED DATA

The advance number of actual initial claims under state programs, unadjusted, totaled 4,971,823 in the week ending April 11, a decrease of 1,239,576 (or -20.0 percent) from the previous week. The seasonal factors had expected an increase of 59,534 (or 1.0 percent) from the previous week. There were 196,364 initial claims in the comparable week in 2019.

The advance unadjusted insured unemployment rate was 8.6 percent during the week ending April 4, an increase of 3.0 percentage points from the prior week. The advance unadjusted number for persons claiming UI benefits in state programs totaled 12,526,711, an increase of 4,358,440 (or 53.4 percent) from the preceding week. The seasonal factors had expected a decrease of 379,746 (or -4.6 percent) from the previous week. A year earlier the rate was 1.2 percent and the volume was 1,730,108.





The total number of people claiming benefits in all programs for the week ending March 28 was 8,206,806, an increase of 4,759,027 from the previous week. There were 1,890,578 persons claiming benefits in all programs in the comparable week in 2019.

No state was triggered "on" the Extended Benefits program during the week ending March 28.

Initial claims for UI benefits filed by former Federal civilian employees totaled 3,395 in the week ending April 4, an increase of 944 from the prior week. There were 2,044 initial claims filed by newly discharged veterans, an increase of 292 from the preceding week.

There were 11,008 former Federal civilian employees claiming UI benefits for the week ending March 28, an increase of 1,630 from the previous week. Newly discharged veterans claiming benefits totaled 6,328, an increase of 849 from the prior week.

The highest insured unemployment rates in the week ending March 28 were in Rhode Island (11.9), Pennsylvania (9.8), Nevada (9.6), Washington (9.3), Connecticut (8.9), Massachusetts (8.7), Minnesota (8.7), Michigan (8.5), Ohio (8.4), and Georgia (8.2).

The largest increases in initial claims for the week ending April 4 were in Georgia (+256,312), Michigan (+84,219), Arizona (+43,488), Texas (+38,982), and Virginia (+34,872), while the largest decreases were in California (-139,511), Pennsylvania (-127,037), Florida (-58,599), Ohio (-48,097), and Massachusetts (-41,776).

UNEMPLOYMENT INSURANCE DATA FOR REGULAR STATE PROGRAMS

WEEK ENDING	**April 11**	**April 4**	**Change**	**March 28**	**Prior Year[1]**
Initial Claims (SA)	5,245,000	6,615,000	-1,370,000	6,867,000	203,000
Initial Claims (NSA)	4,971,823	6,211,399	-1,239,576	6,015,821	196,364
4-Wk Moving Average (SA)	5,508,500	4,267,750	+1,240,750	2,666,750	208,000
WEEK ENDING	**April 4**	**March 28**	**Change**	**March 21**	**Prior Year[1]**
Insured Unemployment (SA)	11,976,000	7,446,000	+4,530,000	3,059,000	1,667,000
Insured Unemployment (NSA)	12,526,711	8,168,271	+4,358,440	3,416,645	1,730,108
4-Wk Moving Average (SA)	6,066,250	3,497,750	+2,568,500	2,061,000	1,705,750
Insured Unemployment Rate (SA)[2]	8.2%	5.1%	+3.1	2.1%	1.2%
Insured Unemployment Rate (NSA)[2]	8.6%	5.6%	+3.0	2.4%	1.2%

INITIAL CLAIMS FILED IN FEDERAL PROGRAMS (UNADJUSTED)

WEEK ENDING	**April 4**	**March 28**	**Change**	**Prior Year[1]**
Federal Employees (UCFE)	3,395	2,451	+944	552
Newly Discharged Veterans (UCX)	2,044	1,752	+292	553

PERSONS CLAIMING UI BENEFITS IN ALL PROGRAMS (UNADJUSTED)

WEEK ENDING	**March 28**	**March 21**	**Change**	**Prior Year[1]**
Regular State	8,157,940	3,411,021	+4,746,919	1,859,082
Federal Employees	11,008	9,378	+1,630	10,434
Newly Discharged Veterans	6,328	5,479	+849	5,879
Extended Benefits[3]	0	0	0	0
State Additional Benefits[4]	5,657	5,449	+208	6,117
STC / Workshare [5]	25,873	16,452	+9,421	9,066
TOTAL	8,206,806	3,447,779	+4,759,027	1,890,578

FOOTNOTES

SA - Seasonally Adjusted Data, NSA - Not Seasonally Adjusted Data

1. Prior year is comparable to most recent data.
2. Most recent week used covered employment of 145,671,710 as denominator.
3. Information on the EB program can be found here: EB Program information
4. Some states maintain additional benefit programs for those claimants who exhaust regular benefits, and when applicable, extended benefits. Information on states that participate, and the extent of benefits paid, can be found starting on page 4-4 of this link: Extensions and Special Programs PDF
5. Information on STC/Worksharing can be found starting on page 4-8 of the following link: Extensions and Special Programs PDF

Advance State Claims - Not Seasonally Adjusted

	Initial Claims Filed During Week Ended April 11			Insured Unemployment For Week Ended April 4		
STATE	Advance	Prior Wk	Change	Advance	Prior Wk	Change
Alabama*	91,079	106,739	-15,660	50,726	52,176	-1,450
Alaska	12,752	14,590	-1,838	35,141	19,845	15,296
Arizona	97,784	132,428	-34,644	116,782	62,597	54,185
Arkansas	34,635	62,086	-27,451	64,356	36,499	27,857
California	660,966	918,814	-257,848	1,440,181	1,076,761	363,420
Colorado	105,073	46,326	58,747	166,170	73,584	92,586
Connecticut	33,962	33,464	498	191,593	147,939	43,654
Delaware	13,272	18,851	-5,579	36,134	19,442	16,692
District of Columbia	9,904	15,329	-5,425	40,440	31,385	9,055
Florida	181,293	169,885	11,408	339,150	98,921	240,229
Georgia	317,526	390,132	-72,606	594,028	360,077	233,951
Hawaii	34,693	53,101	-18,408	48,473	32,123	16,350
Idaho	17,817	30,904	-13,087	58,338	35,915	22,423
Illinois	141,049	201,041	-59,992	453,946	263,057	190,889
Indiana	118,184	127,010	-8,826	152,605	71,737	80,868
Iowa	46,356	64,194	-17,838	128,819	91,631	37,188
Kansas	30,769	49,306	-18,537	79,016	51,425	27,591
Kentucky	115,763	117,575	-1,812	181,130	130,151	50,979
Louisiana	80,045	100,621	-20,576	213,338	116,690	96,648
Maine	13,273	30,910	-17,637	55,033	41,339	13,694
Maryland	60,823	109,489	-48,666	159,533	92,082	67,451
Massachusetts	103,040	139,647	-36,607	358,758	310,211	48,547
Michigan	219,320	388,554	-169,234	744,654	366,426	378,228
Minnesota	89,634	110,260	-20,626	346,689	248,023	98,666
Mississippi	46,160	45,852	308	59,413	29,373	30,040
Missouri	95,785	91,458	4,327	177,479	121,467	56,012
Montana	13,437	21,244	-7,807	54,137	36,819	17,318
Nebraska	16,391	27,054	-10,663	59,295	38,921	20,374
Nevada	60,180	79,285	-19,105	186,619	131,121	55,498
New Hampshire	23,936	39,202	-15266	81,312	52,166	29,146
New Jersey	140,600	214,836	-74,236	431,254	276,119	155,135
New Mexico	19,494	26,132	-6,638	64,651	44,829	19,822
New York	395,949	344,451	51,498	1,126,867	712,544	414,323
North Carolina	137,934	137,422	512	359,151	245,692	113,459
North Dakota	10,378	15,125	-4,747	26,628	16,036	10,592
Ohio	157,218	226,191	-68,973	618,679	450,061	168,618
Oklahoma	48,977	60,534	-11,557	87,512	55,029	32,483
Oregon	50,930	62,788	-11,858	269,538	118,729	150,809
Pennsylvania**	238,357	277,640	-39,283	621,798	566,464	55,334
Puerto Rico	41,829	66,555	-24,726	84,421	49,669	34,752
Rhode Island	22,805	28,243	-5,438	71,944	56,038	15,906
South Carolina	87,686	86,573	1,113	125,376	75,521	49,855
South Dakota	6,152	8,138	-1986	4,453	7,568	-3,115
Tennessee	74,772	112,186	-37,414	206,622	116,179	90,443
Texas	273,567	315,167	-41,600	635,516	374,656	260,860
Utah	24,171	33,040	-8,869	68,207	45,161	23,046
Vermont	9,478	16,474	-6,996	31,377	21,953	9,424
Virgin Islands	3	72	-69	782	658	124
Virginia	106,723	147,369	-40,646	237,367	133,184	104,183
Washington	150,516	171,252	-20,736	451,054	309,411	141,643
West Virginia	14,595	14,494	101	53,993	36,690	17,303
Wisconsin	69,884	104,823	-34,939	263,863	208,387	55,476
Wyoming	4,904	6,543	-1,639	12,370	7,790	4,580
US Total	4,971,823	6,211,399	-1,239,576	12,526,711	8,168,271	4,358,440

Note: Advance claims are not directly comparable to claims reported in prior weeks. Advance claims are reported by the state liable for paying the unemployment compensation, whereas previous weeks reported claims reflect claimants by state of residence. In addition, claims reported as "workshare equivalent" in the previous week are added to the advance claims as a proxy for the current week's "workshare equivalent" activity.

*Denotes OUI estimate.
**Denotes state estimate.

Seasonally Adjusted US Weekly UI Claims (in thousands)

Week Ending	Initial Claims	Change from Prior Week	4-Week Average	Insured Unemployment	Change from Prior Week	4-Week Average	IUR
April 6, 2019	203	-8	212.00	1,667	-38	1,705.75	1.2
April 13, 2019	203	0	208.00	1,659	-8	1,687.50	1.2
April 20, 2019	226	23	210.75	1,682	23	1,678.25	1.2
April 27, 2019	230	4	215.50	1,684	2	1,673.00	1.2
May 4, 2019	225	-5	221.00	1,678	-6	1,675.75	1.2
May 11, 2019	217	-8	224.50	1,683	5	1,681.75	1.2
May 18, 2019	213	-4	221.25	1,675	-8	1,680.00	1.2
May 25, 2019	218	5	218.25	1,695	20	1,682.75	1.2
June 1, 2019	220	2	217.00	1,700	5	1,688.25	1.2
June 8, 2019	220	0	217.75	1,677	-23	1,686.75	1.2
June 15, 2019	219	-1	219.25	1,692	15	1,691.00	1.2
June 22, 2019	224	5	220.75	1,699	7	1,692.00	1.2
June 29, 2019	222	-2	221.25	1,717	18	1,696.25	1.2
July 6, 2019	211	-11	219.00	1,694	-23	1,700.50	1.2
July 13, 2019	217	6	218.50	1,682	-12	1,698.00	1.2
July 20, 2019	211	-6	215.25	1,699	17	1,698.00	1.2
July 27, 2019	216	5	213.75	1,692	-7	1,691.75	1.2
August 3, 2019	214	-2	214.50	1,719	27	1,698.00	1.2
August 10, 2019	218	4	214.75	1,687	-32	1,699.25	1.2
August 17, 2019	215	-3	215.75	1,699	12	1,699.25	1.2
August 24, 2019	215	0	215.50	1,683	-16	1,697.00	1.2
August 31, 2019	219	4	216.75	1,683	0	1,688.00	1.2
September 7, 2019	208	-11	214.25	1,675	-8	1,685.00	1.2
September 14, 2019	211	3	213.25	1,672	-3	1,678.25	1.2
September 21, 2019	215	4	213.25	1,667	-5	1,674.25	1.2
September 28, 2019	218	3	213.00	1,698	31	1,678.00	1.2
October 5, 2019	212	-6	214.00	1,689	-9	1,681.50	1.2
October 12, 2019	218	6	215.75	1,691	2	1,686.25	1.2
October 19, 2019	213	-5	215.25	1,700	9	1,694.50	1.2
October 26, 2019	217	4	215.00	1,695	-5	1,693.75	1.2
November 2, 2019	212	-5	215.00	1,702	7	1,697.00	1.2
November 9, 2019	222	10	216.00	1,697	-5	1,698.50	1.2
November 16, 2019	223	1	218.50	1,665	-32	1,689.75	1.2
November 23, 2019	211	-12	217.00	1,697	32	1,690.25	1.2
November 30, 2019	206	-5	215.50	1,700	3	1,689.75	1.2
December 7, 2019	237	31	219.25	1,725	25	1,696.75	1.2
December 14, 2019	229	-8	220.75	1,716	-9	1,709.50	1.2
December 21, 2019	218	-11	222.50	1,728	12	1,717.25	1.2
December 28, 2019	220	2	226.00	1,775	47	1,736.00	1.2
January 4, 2020	212	-8	219.75	1,759	-16	1,744.50	1.2
January 11, 2020	207	-5	214.25	1,735	-24	1,749.25	1.2
January 18, 2020	220	13	214.75	1,704	-31	1,743.25	1.2
January 25, 2020	212	-8	212.75	1,753	49	1,737.75	1.2
February 1, 2020	201	-11	210.00	1,678	-75	1,717.50	1.2
February 8, 2020	204	3	209.25	1,729	51	1,716.00	1.2
February 15, 2020	215	11	208.00	1,693	-36	1,713.25	1.2
February 22, 2020	220	5	210.00	1,720	27	1,705.00	1.2
February 29, 2020	217	-3	214.00	1,699	-21	1,710.25	1.2
March 7, 2020	211	-6	215.75	1,702	3	1,703.50	1.2
March 14, 2020	282	71	232.50	1,784	82	1,726.25	1.2
March 21, 2020	3,307	3,025	1,004.25	3,059	1,275	2,061.00	2.1
March 28, 2020	6,867	3,560	2,666.75	7,446	4,387	3,497.75	5.1
April 4, 2020	6,615	-252	4,267.75	11,976	4,530	6,066.25	8.2
April 11, 2020	5,245	-1,370	5,508.50				

	INITIAL CLAIMS FILED DURING WEEK ENDED APRIL 4					INSURED UNEMPLOYMENT FOR WEEK ENDED MARCH 28						
		CHANGE FROM						CHANGE FROM				ALL PROGRAMS EXCLUDING
STATE NAME	STATE	LAST WEEK	YEAR AGO	UCFE [1]	UCX [1]	STATE	(%) [2]	LAST WEEK	YEAR AGO	UCFE [1]	UCX [1]	RAILROAD RETIREMENT
Alabama	106739	25755	103848	86	36	52176	2.7	34093	37595	52	36	52264
Alaska	14590	816	13699	5	0	19845	6.5	8672	11262	112	19	19976
Arizona	132428	43488	127399	24	24	62597	2.2	36210	43842	194	49	62840
Arkansas	62086	34330	59836	6	3	36499	3.1	20351	26711	65	37	36601
California	918814	-139511	882587	149	72	1076761	6.2	676196	702938	2101	1031	1079893
Colorado	46326	-15512	44423	26	30	73584	2.8	51628	52849	258	158	74000
Connecticut	33464	237	31135	7	3	147939	8.9	67078	111847	56	61	148056
Delaware	18851	-286	18381	6	6	19442	4.4	7936	14627	8	10	19460
District of Columbia	15329	-540	14890	160	1	31385	5.4	13724	24632	269	5	31659
Florida	169885	-58599	163483	100	94	98921	1.1	63845	65668	120	77	99118
Georgia	390132	256312	385490	73	29	360077	8.2	252200	337057	242	161	360480
Hawaii	53101	4505	51816	2	8	32123	5.2	21141	25499	79	58	32260
Idaho	30904	-2037	29987	17	8	35915	4.9	20392	28488	180	25	36120
Illinois	201041	22620	192165	22	13	263057	4.5	130943	143900	326	138	263521
Indiana	127010	-12164	123972	21	28	71737	2.4	42750	52977	37	45	71819
Iowa	64194	8228	62414	37	15	91631	6.0	37981	67992	70	35	91736
Kansas	49306	-5024	47949	3	1	51425	3.8	33867	42782	30	29	51484
Kentucky	117575	4426	114801	3	2	130151	7.0	105790	112064	157	111	130419
Louisiana	100621	3221	98965	60	34	116690	6.2	58663	103022	47	15	116752
Maine	30910	7140	30171	1	1	41339	6.9	19372	33726	17	0	41356
Maryland	109489	24172	107007	30	60	92082	3.6	44109	65523	186	87	92355
Massachusetts	139647	-41776	135351	62	48	310211	8.7	127106	239220	135	120	310466
Michigan	388554	84219	381872	172	228	366426	8.5	278243	295060	212	102	366740
Minnesota	110260	1165	107124	24	22	248023	8.7	87150	193462	131	74	248228
Mississippi	45852	13837	44903	10	5	29373	2.6	19792	22697	63	30	29466
Missouri	91458	-12833	88819	16	5	121467	4.4	71997	100900	100	45	121612
Montana	21244	481	20505	56	15	36819	8.1	17720	27391	423	33	37275
Nebraska	27054	2329	26465	18	7	38921	4.0	22280	33843	26	7	38954
Nevada	79285	7343	77277	9	7	131121	9.6	72323	112823	177	43	131341
New Hampshire	39202	7824	38705	18	8	52166	8.0	24845	48068	18	8	52192
New Jersey	214836	8583	207129	66	9	276119	6.9	119938	180302	215	260	276594
New Mexico	26132	-1717	25258	5	5	44829	5.6	24742	35436	137	39	45005
New York	344451	-22144	331848	45	21	712544	7.6	397834	572533	347	329	713220
North Carolina	137422	-34723	134283	74	76	245692	5.6	170472	226263	181	204	246077
North Dakota	15125	3307	14853	25	6	16036	3.9	7502	11023	11	9	16056
Ohio	226191	-48097	220180	29	154	450061	8.4	235788	390471	146	264	450471
Oklahoma	60534	12790	58510	56	36	55029	3.5	29761	41382	63	54	55146
Oregon	62788	15290	58320	22	12	118729	6.2	54799	88693	515	70	119314
Pennsylvania	277640	-127037	266513	1326	404	566464	9.8	430756	449333	1518	357	568339
Puerto Rico	66555	21161	65392	15	12	49669	5.8	30439	34145	139	83	49891
Rhode Island	28243	443	27574	4	4	56038	11.9	24191	45926	21	6	56065
South Carolina	86573	20098	84464	32	28	75521	3.6	45180	61482	34	62	75617
South Dakota	8138	1337	7995	11	3	7568	1.8	4030	4902	45	3	7616
Tennessee	112186	19686	107868	84	51	116179	3.9	78638	99398	99	70	116348
Texas	315167	38982	302074	222	252	374656	3.1	229959	262942	578	975	376209
Utah	33040	4508	32014	31	11	45161	3.1	20526	36161	164	23	45348
Vermont	16474	1841	15955	1	0	21953	7.2	8156	17278	8	3	21964
Virgin Islands	72	-178	35	0	0	658	1.9	146	294	0	0	658
Virginia	147369	34872	145214	25	36	133184	3.6	91357	113294	200	226	133610
Washington	171252	-11597	164953	36	80	309411	9.3	151386	255787	477	548	310436
West Virginia	14494	-29	13816	5	10	36690	5.5	15545	25724	52	45	36787
Wisconsin	104823	-6111	99442	43	18	208387	7.3	108813	170083	103	41	208531
Wyoming	6543	147	6199	15	3	7790	2.9	3271	5264	64	8	7862
Totals	6211399	195578	6015328	3395	2044	8168271	5.6	4751626	6306581	11008	6328	8185607

Figures appearing in columns showing over-the-week changes reflect all revisions in data for prior week submitted by state agencies.

1. The Unemployment Compensation program for Federal Employees (UCFE) and the Unemployment Compensation for Ex-servicemembers (UCX) exclude claims filed jointly under other programs to avoid duplication.
2. Rate is not seasonally adjusted. The source of U.S. total covered employment is BLS.

UNADJUSTED INITIAL CLAIMS FOR WEEK ENDED April 4, 2020

STATES WITH AN INCREASE OF MORE THAN 1,000

State	Change	State Supplied Comment
GA	+256,312	Layoffs in the accommodation and food services, trade, health care and social assistance, administrative, support, waste management, and remediation services, and manufacturing industries.
MI	+84,219	Layoffs in the accommodation and food services, retail trade, wholesale trade, and administrative, support, waste management, and remediation services industries.
AZ	+43,488	No comment.
TX	+38,982	Layoffs in the mining, accommodation and food services, manufacturing, health care and social assistance, information, retail trade, administrative, support, waste management, and remediation services, other services, wholesale trade, and arts, entertainment, and recreation industries.
VA	+34,872	Layoffs in the mining industry.
AR	+34,330	No comment.
AL	+25,755	Layoffs in the retail trade, health care and social assistance, administrative, support, waste management, and remediation services, manufacturing, transportation and warehousing, and wholesale trade industries. Increase in initial claims due to COVID-19.
MD	+24,172	No comment.
IL	+22,620	Layoffs in the other services, wholesale trade, retail trade, and accommodation and food services industries.
PR	+21,161	Increase in initial claims due to COVID-19.
SC	+20,098	No comment.
TN	+19,686	Layoffs in the accommodation and food services, retail trade, health care and social assistance, other services, and administrative, support, waste management, and remediation services industries. Increase in initial claims due to COVID-19.
OR	+15,290	Increase in initial claims due to COVID-19.
MS	+13,837	No comment.
OK	+12,790	No comment.
NJ	+8,583	Layoffs in the accommodation and food services, health care and social assistance, and trade industries. Increase in initial claims due to COVID-19.
IA	+8,228	Layoffs in the accommodation and food services, manufacturing, administrative, support, waste management, and remediation services, and construction industries. Increase in initial claims due to COVID-19.
NH	+7,824	Increase in initial claims due to COVID-19.
NV	+7,343	Increase in initial claims due to COVID-19.
ME	+7,140	Layoffs in the retail trade, health care and social assistance, accommodation and food services, manufacturing, educational services, other services, arts, entertainment, and recreation, administrative, support, waste management, and remediation services, construction, and professional, scientific, and technical services industries. Increase in initial claims due to COVID-19.
UT	+4,508	No comment.
HI	+4,505	Increase in initial claims due to COVID-19.
KY	+4,426	No comment.
ND	+3,307	Increase in initial claims due to COVID-19.
LA	+3,221	No comment.
NE	+2,329	No comment.
VT	+1,841	Increase in initial claims due to COVID-19.
SD	+1,337	Increase in initial claims due to COVID-19.
MN	+1,165	Increase in initial claims due to COVID-19.

STATES WITH A DECREASE OF MORE THAN 1,000

State	Change	State Supplied Comment
CA	-139,511	Fewer layoffs in the construction and manufacturing industries.
PA	-127,037	Fewer layoffs in the transportation and warehousing, accommodation and food services, and manufacturing industries.
FL	-58,599	Fewer layoff in the agriculture, forestry, fishing, and hunting, construction, service, and manufacturing industries.
OH	-48,097	No comment.
MA	-41,776	No comment.
NC	-34,723	Fewer layoffs in the accommodation and food services, other services, and administrative, support, waste management, and remediation services industries.
NY	-22,144	Fewer layoffs in the accommodation and food services, manufacturing, and health care and social assistance industries.
CO	-15,512	No comment.
MO	-12,833	Fewer layoffs in the manufacturing, accommodation and food services, and transportation and warehousing industries.
IN	-12,164	No comment.
WA	-11,597	No comment.
WI	-6,111	No comment.
KS	-5,024	No comment.
ID	-2,037	No comment.
NM	-1,717	No comment.

TECHNICAL NOTES

This news release presents the weekly unemployment insurance (UI) claims reported by each state's unemployment insurance program offices. These claims may be used for monitoring workload volume, assessing state program operations and for assessing labor market conditions. States initially report claims directly taken by the state liable for the benefit payments, regardless of where the claimant who filed the claim resided. These are the basis for the advance initial claims and continued claims reported each week. These data come from ETA 538, Advance Weekly Initial and Continued Claims Report. The following week initial claims and continued claims are revised based on a second reporting by states that reflect the claimants by state of residence. These data come from the ETA 539, Weekly Claims and Extended Benefits Trigger Data Report.

A. Initial Claims

An initial claim is a claim filed by an unemployed individual after a separation from an employer. The claimant requests a determination of basic eligibility for the UI program. When an initial claim is filed with a state, certain programmatic activities take place and these result in activity counts including the count of initial claims. The count of U.S. initial claims for unemployment insurance is a leading economic indicator because it is an indication of emerging labor market conditions in the country. However, these are weekly administrative data which are difficult to seasonally adjust, making the series subject to some volatility.

B. Continued Weeks Claimed

A person who has already filed an initial claim and who has experienced a week of unemployment then files a continued claim to claim benefits for that week of unemployment. Continued claims are also referred to as insured unemployment. The count of U.S. continued weeks claimed is also a good indicator of labor market conditions. Continued claims reflect the current number of insured unemployed workers filing for UI benefits in the nation. While continued claims are not a leading indicator (they roughly coincide with economic cycles at their peaks and lag at cycle troughs), they provide confirming evidence of the direction of the U.S. economy.

C. Seasonal Adjustments and Annual Revisions

Over the course of a year, the weekly changes in the levels of initial claims and continued claims undergo regularly occurring fluctuations. These fluctuations may result from seasonal changes in weather, major holidays, the opening and closing of schools, or other similar events. Because these seasonal events follow a more or less regular pattern each year, their influence on the level of a series can be tempered by adjusting for regular seasonal variation. These adjustments make trend and cycle developments easier to spot. At the beginning of each calendar year, the Bureau of Labor Statistics provides the Employment and Training Administration (ETA) with a set of seasonal factors to apply to the unadjusted data during that year. Concurrent with the implementation and release of the new seasonal factors, ETA incorporates revisions to the UI claims historical series caused by updates to the unadjusted data.

Weekly Claims Archives
Weekly Claims Data

U.S. Department of Labor news materials are accessible at http://www.dol.gov. The Department's Reasonable Accommodation Resource Center converts Departmental information and documents into alternative formats, which include Braille and large print. For alternative format requests, please contact the Department at (202) 693-7828 (voice) or (800) 877-8339 (federal relay).

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News Release

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TRANSMISSION OF MATERIALS IN THIS RELEASE IS EMBARGOED UNTIL
8:30 A.M. (Eastern) Thursday, April 23, 2020

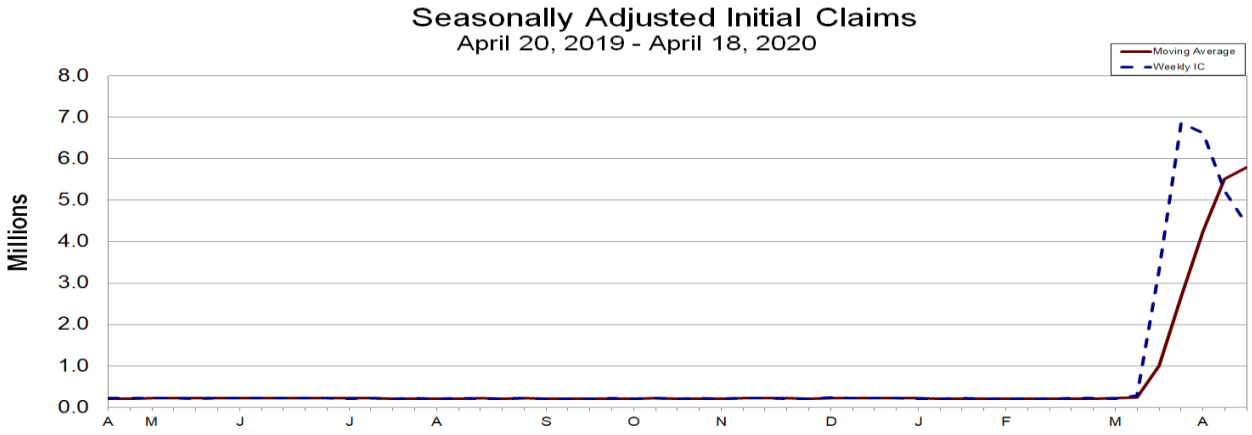
COVID-19 Impact
The COVID-19 virus continues to impact the number of initial claims and insured unemployment.

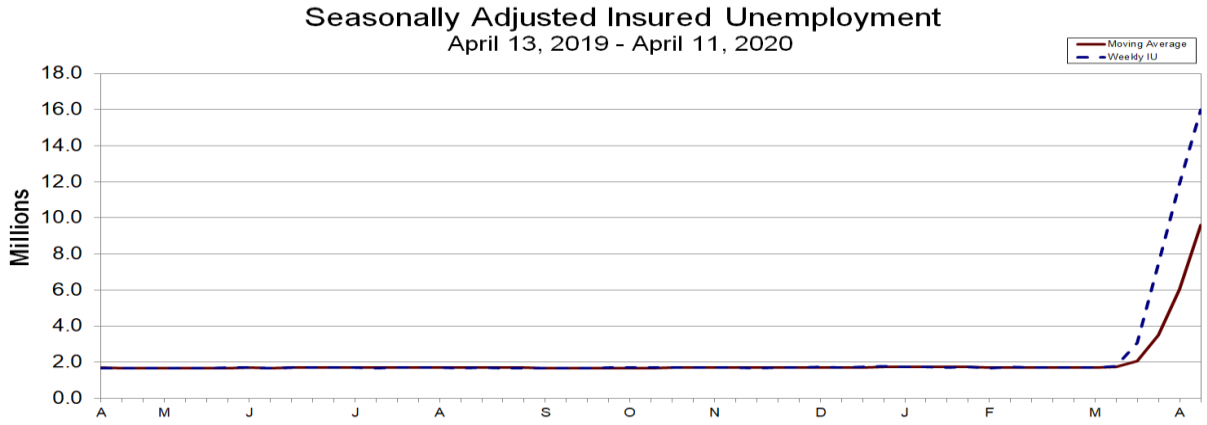
UNEMPLOYMENT INSURANCE WEEKLY CLAIMS

SEASONALLY ADJUSTED DATA

In the week ending April 18, the advance figure for seasonally adjusted **initial claims** was 4,427,000, a decrease of 810,000 from the previous week's revised level. The previous week's level was revised down by 8,000 from 5,245,000 to 5,237,000. The 4-week moving average was 5,786,500, an increase of 280,000 from the previous week's revised average. The previous week's average was revised down by 2,000 from 5,508,500 to 5,506,500.

The advance seasonally adjusted **insured unemployment rate** was 11.0 percent for the week ending April 11, an increase of 2.8 percentage points from the previous week's unrevised rate. This marks the highest level of the seasonally adjusted insured unemployment rate in the history of the seasonally adjusted series. The advance number for seasonally adjusted **insured unemployment** during the week ending April 11 was 15,976,000, an increase of 4,064,000 from the previous week's revised level. This marks the highest level of seasonally adjusted insured unemployment in the history of the seasonally adjusted series. The previous week's level was revised down by 64,000 from 11,976,000 to 11,912,000. The 4-week moving average was 9,598,250, an increase of 3,548,000 from the previous week's revised average. The previous week's average was revised down by 16,000 from 6,066,250 to 6,050,250.

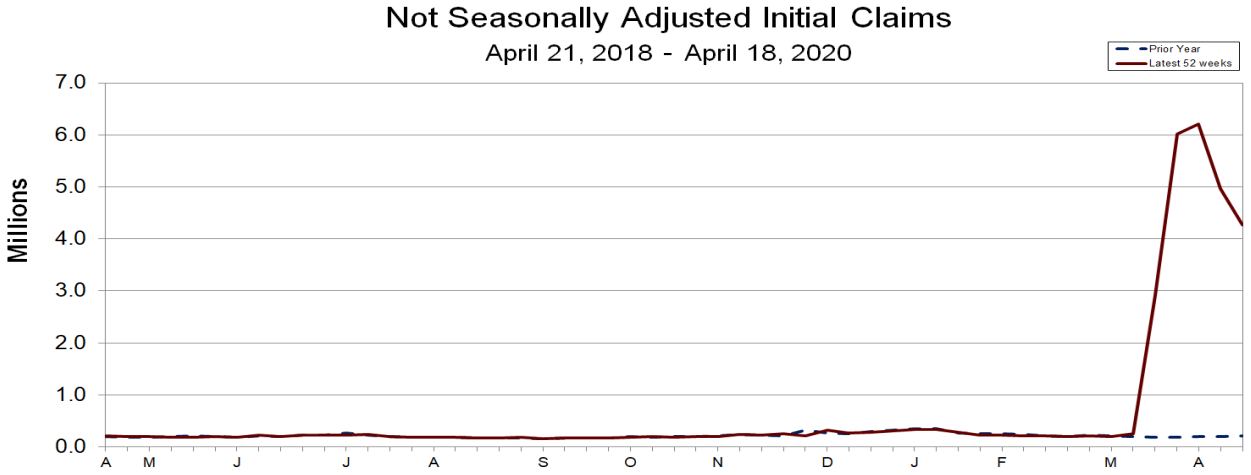


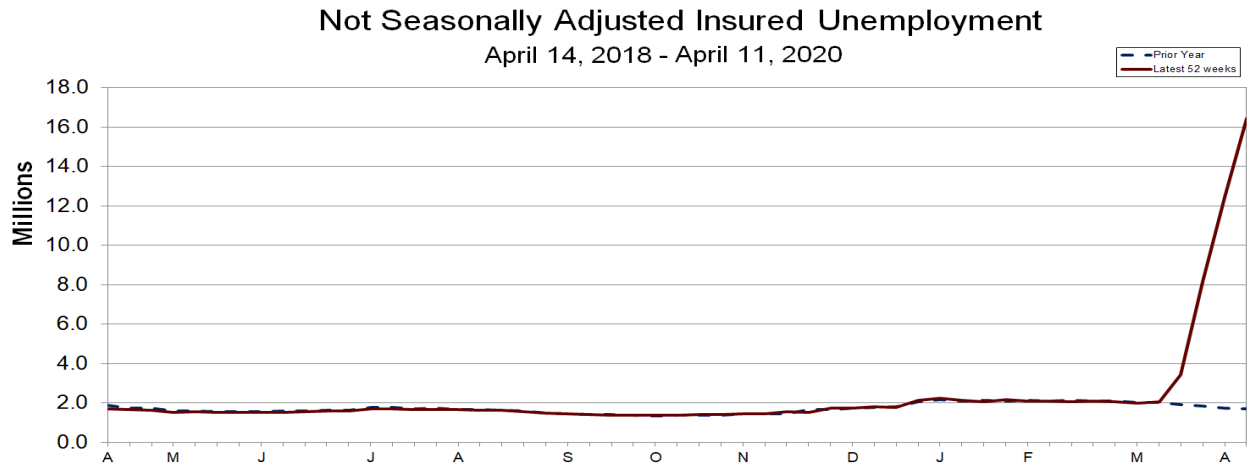


UNADJUSTED DATA

The advance number of actual initial claims under state programs, unadjusted, totaled 4,267,395 in the week ending April 18, a decrease of 697,173 (or -14.0 percent) from the previous week. The seasonal factors had expected an increase of 83,790 (or 1.7 percent) from the previous week. There were 211,762 initial claims in the comparable week in 2019.

The advance unadjusted insured unemployment rate was 11.3 percent during the week ending April 11, an increase of 2.7 percentage points from the prior week. The advance unadjusted number for persons claiming UI benefits in state programs totaled 16,438,933, an increase of 3,978,614 (or 31.9 percent) from the preceding week. The seasonal factors had expected a decrease of 202,510 (or -1.6 percent) from the previous week. A year earlier the rate was 1.2 percent and the volume was 1,703,576.





The total number of people claiming benefits in all programs for the week ending April 4 was 12,506,993, an increase of 4,300,016 from the previous week. There were 1,757,864 persons claiming benefits in all programs in the comparable week in 2019.

No state was triggered "on" the Extended Benefits program during the week ending April 4.

Initial claims for UI benefits filed by former Federal civilian employees totaled 2,844 in the week ending April 11, a decrease of 551 from the prior week. There were 1,821 initial claims filed by newly discharged veterans, a decrease of 223 from the preceding week.

There were 11,562 former Federal civilian employees claiming UI benefits for the week ending April 4, an increase of 535 from the previous week. Newly discharged veterans claiming benefits totaled 7,068, an increase of 727 from the prior week.

The highest insured unemployment rates in the week ending April 4 were in Michigan (17.4), Rhode Island (15.0), Nevada (13.7), Georgia (13.6), Washington (13.2), New Hampshire (12.2), Minnesota (11.9), New York (11.9), Montana (11.7), and Ohio (11.6).

The largest increases in initial claims for the week ending April 11 were in Colorado (+58,246), New York (+50,250), Missouri (+10,668), Florida (+10,534), and North Carolina (+2,733), while the largest decreases were in California (-263,342), Michigan (-166,347), New Jersey (-73,416), Georgia (-70,551), and Ohio (-66,874).

UNEMPLOYMENT INSURANCE DATA FOR REGULAR STATE PROGRAMS

WEEK ENDING	**April 18**	**April 11**	**Change**	**April 4**	**Prior Year[1]**
Initial Claims (SA)	4,427,000	5,237,000	-810,000	6,615,000	226,000
Initial Claims (NSA)	4,267,395	4,964,568	-697,173	6,211,406	211,762
4-Wk Moving Average (SA)	5,786,500	5,506,500	+280,000	4,267,750	210,750
WEEK ENDING	**April 11**	**April 4**	**Change**	**March 28**	**Prior Year[1]**
Insured Unemployment (SA)	15,976,000	11,912,000	+4,064,000	7,446,000	1,659,000
Insured Unemployment (NSA)	16,438,933	12,460,319	+3,978,614	8,168,375	1,703,576
4-Wk Moving Average (SA)	9,598,250	6,050,250	+3,548,000	3,497,750	1,687,500
Insured Unemployment Rate (SA)[2]	11.0%	8.2%	+2.8	5.1%	1.2%
Insured Unemployment Rate (NSA)[2]	11.3%	8.6%	+2.7	5.6%	1.2%

INITIAL CLAIMS FILED IN FEDERAL PROGRAMS (UNADJUSTED)

WEEK ENDING	**April 11**	**April 4**	**Change**	**Prior Year[1]**
Federal Employees (UCFE)	2,844	3,395	-551	572
Newly Discharged Veterans (UCX)	1,821	2,044	-223	526

PERSONS CLAIMING UI BENEFITS IN ALL PROGRAMS (UNADJUSTED)

WEEK ENDING	**April 4**	**March 28**	**Change**	**Prior Year[1]**
Regular State	12,442,955	8,158,014	+4,284,941	1,727,352
Federal Employees	11,562	11,027	+535	9,120
Newly Discharged Veterans	7,068	6,341	+727	5,837
Extended Benefits[3]	138	0	+138	0
State Additional Benefits[4]	5,406	5,657	-251	6,088
STC / Workshare [5]	39,864	25,938	+13,926	9,467
TOTAL	12,506,993	8,206,977	+4,300,016	1,757,864

FOOTNOTES

SA - Seasonally Adjusted Data, NSA - Not Seasonally Adjusted Data

1. Prior year is comparable to most recent data.
2. Most recent week used covered employment of 145,671,710 as denominator.
3. Information on the EB program can be found here: EB Program information
4. Some states maintain additional benefit programs for those claimants who exhaust regular benefits, and when applicable, extended benefits. Information on states that participate, and the extent of benefits paid, can be found starting on page 4-4 of this link: Extensions and Special Programs PDF
5. Information on STC/Worksharing can be found starting on page 4-8 of the following link: Extensions and Special Programs PDF

Advance State Claims - Not Seasonally Adjusted

	Initial Claims Filed During Week Ended April 18			Insured Unemployment For Week Ended April 11		
STATE	Advance	Prior Wk	Change	Advance	Prior Wk	Change
Alabama	65,431	77,515	-12,084	125,764	95,325	30,439
Alaska	13,027	12,007	1,020	47,784	35,365	12,419
Arizona	71,843	98,531	-26,688	166,193	120,592	45,601
Arkansas	24,236	35,629	-11,393	88,896	66,511	22,385
California	533,568	655,472	-121,904	2,434,265	1,429,954	1,004,311
Colorado	68,667	104,572	-35,905	171,517	166,593	4,924
Connecticut	102,757	34,050	68,707	308,614	189,196	119,418
Delaware	9,294	13,258	-3,964	45,377	29,577	15,800
District of Columbia	8,591	9,974	-1,383	45,741	42,224	3,517
Florida*	505,137	180,419	324,718	177,009	339,448	-162,439
Georgia	243,677	319,581	-75,904	609,575	595,418	14,157
Hawaii	26,477	34,717	-8,240	72,504	48,205	24,299
Idaho	12,456	18,531	-6,075	66,708	59,139	7,569
Illinois	102,736	141,160	-38,424	570,227	452,905	117,322
Indiana	75,483	113,755	-38,272	214,171	147,583	66,588
Iowa	27,912	43,889	-15,977	151,846	127,332	24,514
Kansas	31,920	29,873	2,047	98,533	78,334	20,199
Kentucky	103,548	116,277	-12,729	198,926	182,097	16,829
Louisiana	92,039	79,653	12,386	241,124	217,532	23,592
Maine	11,446	13,488	-2,042	65,233	55,723	9,510
Maryland	46,676	62,904	-16,228	198,797	160,906	37,891
Massachusetts	80,345	103,813	-23,468	463,974	361,600	102,374
Michigan	134,119	222,207	-88,088	944,947	749,011	195,936
Minnesota	74,873	93,133	-18,260	399,379	341,578	57,801
Mississippi	35,843	45,748	-9,905	91,748	60,737	31,011
Missouri	52,678	102,126	-49,448	226,059	178,710	47,349
Montana	10,509	14,275	-3,766	65,367	53,482	11,885
Nebraska	12,340	16,279	-3,939	70,911	60,416	10,495
Nevada	40,909	58,641	-17,732	229,072	189,007	40,065
New Hampshire	19,110	25,273	-6163	93,771	79,979	13,792
New Jersey	139,277	141,420	-2,143	557,731	429,388	128,343
New Mexico	13,338	19,043	-5,705	81,441	62,686	18,755
New York	204,716	394,701	-189,985	1,360,820	1,121,191	239,629
North Carolina	104,515	140,155	-35,640	463,589	362,989	100,600
North Dakota	9,042	9,502	-460	36,378	24,554	11,824
Ohio	108,801	159,317	-50,516	713,040	622,669	90,371
Oklahoma	40,297	54,481	-14,184	111,198	88,330	22,868
Oregon	35,101	54,581	-19,480	343,321	176,154	167,167
Pennsylvania*	198,081	234,868	-36,787	1,088,179	614,196	473,983
Puerto Rico	26,248	42,074	-15,826	107,338	86,474	20,864
Rhode Island	17,578	22,509	-4,931	79,944	70,935	9,009
South Carolina	73,116	89,147	-16,031	178,083	126,994	51,089
South Dakota	5,128	6,359	-1231	19,772	14,431	5,341
Tennessee	68,968	71,887	-2,919	276,220	206,472	69,748
Texas	280,406	274,257	6,149	917,757	632,470	285,287
Utah	19,751	24,037	-4,286	86,599	71,544	15,055
Vermont	6,434	9,662	-3,228	64,408	31,204	33,204
Virgin Islands	1	6	-5	1,324	776	548
Virginia	84,387	104,619	-20,232	298,269	236,791	61,478
Washington	89,105	144,455	-55,350	548,564	442,936	105,628
West Virginia	46,251	14,944	31,307	104,904	48,597	56,307
Wisconsin	55,886	70,000	-14,114	300,422	262,847	37,575
Wyoming	3,321	5,794	-2,473	15,600	11,212	4,388
US Total	4,267,395	4,964,568	-697,173	16,438,933	12,460,319	3,978,614

Note: Advance claims are not directly comparable to claims reported in prior weeks. Advance claims are reported by the state liable for paying the unemployment compensation, whereas previous weeks reported claims reflect claimants by state of residence. In addition, claims reported as "workshare equivalent" in the previous week are added to the advance claims as a proxy for the current week's "workshare equivalent" activity.

*Denotes state estimate.

Seasonally Adjusted US Weekly UI Claims (in thousands)

Week Ending	Initial Claims	Change from Prior Week	4-Week Average	Insured Unemployment	Change from Prior Week	4-Week Average	IUR
April 13, 2019	203	0	208.00	1,659	-8	1,687.50	1.2
April 20, 2019	226	23	210.75	1,682	23	1,678.25	1.2
April 27, 2019	230	4	215.50	1,684	2	1,673.00	1.2
May 4, 2019	225	-5	221.00	1,678	-6	1,675.75	1.2
May 11, 2019	217	-8	224.50	1,683	5	1,681.75	1.2
May 18, 2019	213	-4	221.25	1,675	-8	1,680.00	1.2
May 25, 2019	218	5	218.25	1,695	20	1,682.75	1.2
June 1, 2019	220	2	217.00	1,700	5	1,688.25	1.2
June 8, 2019	220	0	217.75	1,677	-23	1,686.75	1.2
June 15, 2019	219	-1	219.25	1,692	15	1,691.00	1.2
June 22, 2019	224	5	220.75	1,699	7	1,692.00	1.2
June 29, 2019	222	-2	221.25	1,717	18	1,696.25	1.2
July 6, 2019	211	-11	219.00	1,694	-23	1,700.50	1.2
July 13, 2019	217	6	218.50	1,682	-12	1,698.00	1.2
July 20, 2019	211	-6	215.25	1,699	17	1,698.00	1.2
July 27, 2019	216	5	213.75	1,692	-7	1,691.75	1.2
August 3, 2019	214	-2	214.50	1,719	27	1,698.00	1.2
August 10, 2019	218	4	214.75	1,687	-32	1,699.25	1.2
August 17, 2019	215	-3	215.75	1,699	12	1,699.25	1.2
August 24, 2019	215	0	215.50	1,683	-16	1,697.00	1.2
August 31, 2019	219	4	216.75	1,683	0	1,688.00	1.2
September 7, 2019	208	-11	214.25	1,675	-8	1,685.00	1.2
September 14, 2019	211	3	213.25	1,672	-3	1,678.25	1.2
September 21, 2019	215	4	213.25	1,667	-5	1,674.25	1.2
September 28, 2019	218	3	213.00	1,698	31	1,678.00	1.2
October 5, 2019	212	-6	214.00	1,689	-9	1,681.50	1.2
October 12, 2019	218	6	215.75	1,691	2	1,686.25	1.2
October 19, 2019	213	-5	215.25	1,700	9	1,694.50	1.2
October 26, 2019	217	4	215.00	1,695	-5	1,693.75	1.2
November 2, 2019	212	-5	215.00	1,702	7	1,697.00	1.2
November 9, 2019	222	10	216.00	1,697	-5	1,698.50	1.2
November 16, 2019	223	1	218.50	1,665	-32	1,689.75	1.2
November 23, 2019	211	-12	217.00	1,697	32	1,690.25	1.2
November 30, 2019	206	-5	215.50	1,700	3	1,689.75	1.2
December 7, 2019	237	31	219.25	1,725	25	1,696.75	1.2
December 14, 2019	229	-8	220.75	1,716	-9	1,709.50	1.2
December 21, 2019	218	-11	222.50	1,728	12	1,717.25	1.2
December 28, 2019	220	2	226.00	1,775	47	1,736.00	1.2
January 4, 2020	212	-8	219.75	1,759	-16	1,744.50	1.2
January 11, 2020	207	-5	214.25	1,735	-24	1,749.25	1.2
January 18, 2020	220	13	214.75	1,704	-31	1,743.25	1.2
January 25, 2020	212	-8	212.75	1,753	49	1,737.75	1.2
February 1, 2020	201	-11	210.00	1,678	-75	1,717.50	1.2
February 8, 2020	204	3	209.25	1,729	51	1,716.00	1.2
February 15, 2020	215	11	208.00	1,693	-36	1,713.25	1.2
February 22, 2020	220	5	210.00	1,720	27	1,705.00	1.2
February 29, 2020	217	-3	214.00	1,699	-21	1,710.25	1.2
March 7, 2020	211	-6	215.75	1,702	3	1,703.50	1.2
March 14, 2020	282	71	232.50	1,784	82	1,726.25	1.2
March 21, 2020	3,307	3,025	1,004.25	3,059	1,275	2,061.00	2.1
March 28, 2020	6,867	3,560	2,666.75	7,446	4,387	3,497.75	5.1
April 4, 2020	6,615	-252	4,267.75	11,912	4,466	6,050.25	8.2
April 11, 2020	5,237	-1,378	5,506.50	15,976	4,064	9,598.25	11.0
April 18, 2020	4,427	-810	5,786.50				

STATE NAME	INITIAL CLAIMS FILED DURING WEEK ENDED APRIL 11					INSURED UNEMPLOYMENT FOR WEEK ENDED APRIL 4						
	STATE	CHANGE FROM LAST WEEK	CHANGE FROM YEAR AGO	UCFE [1]	UCX [1]	STATE	(%) [2]	CHANGE FROM LAST WEEK	CHANGE FROM YEAR AGO	UCFE [1]	UCX [1]	ALL PROGRAMS EXCLUDING RAILROAD RETIREMENT
Alabama	77515	-29224	75134	64	22	95325	4.9	43149	81358	52	38	95415
Alaska	12007	-2583	11015	6	2	35365	11.5	15520	27512	123	17	35505
Arizona	98531	-33897	92683	21	9	120592	4.3	57995	100856	182	88	120862
Arkansas	35629	-26457	34178	3	2	66511	5.6	30012	56252	66	36	66613
California	655472	-263342	616043	235	222	1429954	8.3	353193	1082931	2120	943	1433017
Colorado	104572	58246	102535	17	69	166593	6.2	93009	148357	202	133	166932
Connecticut	34050	586	30596	11	9	189196	11.4	41257	155696	61	58	189316
Delaware	13258	-5593	12776	3	11	29577	6.6	10135	25057	9	11	29597
District of Columbia	9974	-5355	9555	160	1	42224	7.3	10839	35509	347	11	42582
Florida	180419	10534	174074	85	109	339448	3.9	240527	306205	207	220	339875
Georgia	319581	-70551	314333	76	35	595418	13.6	235341	570581	309	187	595914
Hawaii	34717	-18384	33589	2	4	48205	7.7	16008	41626	60	44	48309
Idaho	18531	-12373	17583	14	2	59139	8.1	23224	52668	136	29	59305
Illinois	141160	-59881	133432	14	16	452905	7.7	189848	342660	379	180	453470
Indiana	113755	-13255	111385	38	23	147583	4.9	75846	131860	38	56	147677
Iowa	43889	-20305	42053	42	14	127332	8.3	35701	107015	87	40	127459
Kansas	29873	-19433	28575	2	0	78334	5.7	26909	70335	31	26	78391
Kentucky	116277	-1298	114169	4	6	182097	9.8	51946	165319	129	133	182359
Louisiana	79653	-20968	77766	69	38	217532	11.5	100842	204118	74	34	217681
Maine	13488	-17422	12777	0	0	55723	9.2	14384	48532	54	11	55788
Maryland	62904	-46592	60124	24	22	160906	6.3	68794	135412	193	128	161227
Massachusetts	103813	-35834	99348	62	41	361600	10.1	51389	297111	138	147	361885
Michigan	222207	-166347	216628	125	143	749011	17.4	382585	688206	262	188	749461
Minnesota	93133	-17127	90329	35	31	341578	11.9	93555	292567	163	80	341821
Mississippi	45748	-104	44655	2	4	60737	5.5	31364	54094	72	34	60874
Missouri	102126	10668	99302	9	7	178710	6.5	57243	160677	111	57	178914
Montana	14275	-6969	13460	27	12	53482	11.7	16663	45386	365	33	53880
Nebraska	16279	-10775	15713	10	2	60416	6.3	21495	56144	35	10	60461
Nevada	58641	-20644	56445	4	5	189007	13.7	57886	171556	136	54	189197
New Hampshire	25273	-13929	24792	8	10	79979	12.2	27813	76126	25	9	80013
New Jersey	141420	-73416	133779	37	5	429388	10.7	153269	340625	217	247	429852
New Mexico	19043	-7089	18228	1	3	62686	7.8	17857	53540	129	41	62856
New York	394701	50250	382570	33	38	1121191	11.9	408647	988567	377	361	1121929
North Carolina	140155	2733	137103	87	75	362989	8.2	117297	343740	267	251	363512
North Dakota	9502	-5623	9230	11	6	24554	5.9	8518	20100	9	9	24573
Ohio	159317	-66874	154082	23	81	622669	11.6	172608	567728	170	397	623236
Oklahoma	54481	-6053	52657	57	28	88330	5.6	33301	74882	54	56	88440
Oregon	54581	-8207	50229	35	8	176154	9.2	57425	147518	525	74	176753
Pennsylvania	234868	-42772	223373	987	332	614196	10.6	47732	513372	1742	379	616317
Puerto Rico	42074	-24481	40644	8	9	86474	10.1	36805	71477	181	71	86732
Rhode Island	22509	-5734	21758	10	4	70935	15.0	14897	62069	23	7	70965
South Carolina	89147	2574	87109	41	40	126994	6.1	51473	113460	34	79	127113
South Dakota	6359	-1779	6278	9	0	14431	3.5	6863	12304	48	3	14482
Tennessee	71887	-40299	69723	49	28	206472	6.9	90293	188530	104	84	206660
Texas	274257	-40910	260389	166	195	632470	5.1	257814	524763	488	954	633912
Utah	24037	-9003	22673	28	9	71544	4.9	26383	63543	29	0	71573
Vermont	9662	-6812	8964	0	0	31204	10.3	9251	26823	10	2	31216
Virgin Islands	6	-66	-6	0	0	776	2.2	118	240	6	0	782
Virginia	104619	-42750	102359	18	19	236791	6.3	103607	217627	247	282	237320
Washington	144455	-26797	137516	21	42	442936	13.2	133525	390355	517	634	444087
West Virginia	14944	450	13986	6	17	48597	7.3	11907	38590	49	50	48696
Wisconsin	70000	-34823	65316	33	11	262847	9.2	54460	229724	108	47	263002
Wyoming	5794	-749	5197	12	0	11212	4.2	3422	8908	62	5	11279
Totals	4964568	-1246838	4768204	2844	1821	12460319	8.6	4291944	10730211	11562	7068	12479087

Figures appearing in columns showing over-the-week changes reflect all revisions in data for prior week submitted by state agencies.

1. The Unemployment Compensation program for Federal Employees (UCFE) and the Unemployment Compensation for Ex-servicemembers (UCX) exclude claims filed jointly under other programs to avoid duplication.
2. Rate is not seasonally adjusted. The source of U.S. total covered employment is BLS.

UNADJUSTED INITIAL CLAIMS FOR WEEK ENDED APRIL 11, 2020

STATES WITH AN INCREASE OF MORE THAN 1,000

State	Change	State Supplied Comment
CO	+58,246	Layoffs in the health care and social assistance, arts, entertainment, and recreation, and other services industries. Increase in initial claims due to COVID-19.
NY	+50,250	Layoffs in the retail trade, health care and social assistance, and construction industries.
MO	+10,668	Layoffs in the accommodation and food services and administrative, support, waste management, and remediation services industries.
FL	+10,534	Layoffs in the construction, manufacturing, retail trade, wholesale trade, accommodation and food services, and health care and social assistance industries.
NC	+2,733	Layoffs in the health care and social assistance and manufacturing industries.
SC	+2,574	No comment.

STATES WITH A DECREASE OF MORE THAN 1,000

State	Change	State Supplied Comment
CA	-263,342	Fewer layoffs in the service and retail trade industries.
MI	-166,347	Fewer layoffs in the manufacturing, retail trade, and accommodation and food services industries.
NJ	-73,416	No comment.
GA	-70,551	Fewer layoffs in the accommodation and food services, public administration, retail trade, health care and social assistance, and administrative, support, waste management, and remediation services industries.
OH	-66,874	No comment.
IL	-59,881	No comment.
MD	-46,592	No comment.
PA	-42,772	Fewer layoffs in the arts, entertainment, and recreation, other services, and agriculture, forestry, fishing, and hunting industries.
VA	-42,750	No comment.
TX	-40,910	No comment.
TN	-40,299	No comment.
MA	-35,834	No comment.
WI	-34,823	Fewer layoffs in the manufacturing and accommodation and food services industries.
AZ	-33,897	No comment.
AL	-29,224	Fewer layoffs in the accommodation and food services, health care and social assistance, retail trade, and administrative, support, waste management, and remediation services industries.
WA	-26,797	No comment.
AR	-26,457	No comment.
PR	-24,481	No comment.
LA	-20,968	No comment.
NV	-20,644	No comment.
IA	-20,305	No comment.
KS	-19,433	No comment.
HI	-18,384	No comment.
ME	-17,422	Fewer layoffs in the manufacturing, health care and social assistance, accommodation and food services, educational services, professional, scientific, and technical services, arts, entertainment, and recreation, administrative, support, waste management, and remediation services, wholesale trade, and construction industries.
MN	-17,127	No comment.
NH	-13,929	No comment.
IN	-13,255	No comment.
ID	-12,373	No comment.

NE	-10,775	No comment.
UT	-9,003	No comment.
OR	-8,207	No comment.
NM	-7,089	No comment.
MT	-6,969	No comment.
VT	-6,812	No comment.
OK	-6,053	No comment.
RI	-5,734	No comment.
ND	-5,623	No comment.
DE	-5,593	No comment.
DC	-5,355	No comment.
AK	-2,583	No comment.
SD	-1,779	No comment.
KY	-1,298	No comment.

TECHNICAL NOTES

This news release presents the weekly unemployment insurance (UI) claims reported by each state's unemployment insurance program offices. These claims may be used for monitoring workload volume, assessing state program operations and for assessing labor market conditions. States initially report claims directly taken by the state liable for the benefit payments, regardless of where the claimant who filed the claim resided. These are the basis for the advance initial claims and continued claims reported each week. These data come from ETA 538, Advance Weekly Initial and Continued Claims Report. The following week initial claims and continued claims are revised based on a second reporting by states that reflect the claimants by state of residence. These data come from the ETA 539, Weekly Claims and Extended Benefits Trigger Data Report.

A. Initial Claims

An initial claim is a claim filed by an unemployed individual after a separation from an employer. The claimant requests a determination of basic eligibility for the UI program. When an initial claim is filed with a state, certain programmatic activities take place and these result in activity counts including the count of initial claims. The count of U.S. initial claims for unemployment insurance is a leading economic indicator because it is an indication of emerging labor market conditions in the country. However, these are weekly administrative data which are difficult to seasonally adjust, making the series subject to some volatility.

B. Continued Weeks Claimed

A person who has already filed an initial claim and who has experienced a week of unemployment then files a continued claim to claim benefits for that week of unemployment. Continued claims are also referred to as insured unemployment. The count of U.S. continued weeks claimed is also a good indicator of labor market conditions. Continued claims reflect the current number of insured unemployed workers filing for UI benefits in the nation. While continued claims are not a leading indicator (they roughly coincide with economic cycles at their peaks and lag at cycle troughs), they provide confirming evidence of the direction of the U.S. economy.

C. Seasonal Adjustments and Annual Revisions

Over the course of a year, the weekly changes in the levels of initial claims and continued claims undergo regularly occurring fluctuations. These fluctuations may result from seasonal changes in weather, major holidays, the opening and closing of schools, or other similar events. Because these seasonal events follow a more or less regular pattern each year, their influence on the level of a series can be tempered by adjusting for regular seasonal variation. These adjustments make trend and cycle developments easier to spot. At the beginning of each calendar year, the Bureau of Labor Statistics provides the Employment and Training Administration (ETA) with a set of seasonal factors to apply to the unadjusted data during that year. Concurrent with the implementation and release of the new seasonal factors, ETA incorporates revisions to the UI claims historical series caused by updates to the unadjusted data.

Weekly Claims Archives
Weekly Claims Data

U.S. Department of Labor news materials are accessible at http://www.dol.gov. The Department's Reasonable Accommodation Resource Center converts Departmental information and documents into alternative formats, which include Braille and large print. For alternative format requests, please contact the Department at (202) 693-7828 (voice) or (800) 877-8339 (federal relay).

U.S. Department of Labor
Employment and Training Administration
Washington, D.C. 20210
Release Number: USDL 20-691-NAT

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U.S. BUREAU OF LABOR STATISTICS

Economic News Release

CES CPS PRINT:

Employment Situation Summary

Transmission of material in this news release is embargoed until 8:30 a.m. (EDT) Friday, May 8, 2020

USDL-20-0815

Technical information:
Household data: cpsinfo@bls.gov * www.bls.gov/cps
Establishment data: cesinfo@bls.gov * www.bls.gov/ces

Media contact: (202) 691-5902 * PressOffice@bls.gov

(NOTE: On May 11, 2020, BLS corrected errors in national estimates for seasonally adjusted all employees in professional and technical services, professional and business services, private service-providing, service-providing, total private, and total nonfarm. Tables affected are Summary table B, B-1, B-4, and B-5. The corrected change in total nonfarm employment for April is 37,000 lower than initially reported. Estimates in the LABSTAT database and in this news release were corrected for February, March, and April 2020. BLS also corrected other supporting documentation on www.bls.gov/ces/.)

THE EMPLOYMENT SITUATION -- APRIL 2020

Total nonfarm payroll employment fell by 20.5 million in April, and the unemployment rate rose to 14.7 percent, the U.S. Bureau of Labor Statistics reported today. The changes in these measures reflect the effects of the coronavirus (COVID-19) pandemic and efforts to contain it. Employment fell sharply in all major industry sectors, with particularly heavy job losses in leisure and hospitality.

This news release presents statistics from two monthly surveys. The household survey measures labor force status, including unemployment, by demographic characteristics. The establishment survey measures nonfarm employment, hours, and earnings by industry. For more information about the concepts and statistical methodology used in these two surveys, see the Technical Note.

Household Survey Data

In April, the unemployment rate increased by 10.3 percentage points to 14.7 percent. This is the highest rate and the largest over-the-month increase in the history of the series (seasonally adjusted data are available back to January 1948). The number of unemployed persons rose by 15.9 million to 23.1 million in April. The sharp increases in these measures reflect the effects of the coronavirus pandemic and efforts to contain it. (See table A-1. For more information about how the household survey and its measures were affected by the coronavirus pandemic, see the box at the end of the news release.)

In April, unemployment rates rose sharply among all major worker groups. The rate was 13.0 percent for adult men, 15.5 percent for adult women, 31.9 percent for teenagers, 14.2 percent for Whites, 16.7 percent for Blacks, 14.5 percent for Asians, and 18.9 percent for Hispanics. The rates for all of these groups, with the exception of Blacks, represent record highs for their respective series. (See tables A-1, A-2, and A-3.)

The number of unemployed persons who reported being on temporary layoff increased about ten-fold to 18.1 million in April. The number of permanent job losers increased by 544,000 to 2.0 million. (See table A-11.)

In April, the number of unemployed persons who were jobless less than 5 weeks increased by 10.7 million to 14.3 million, accounting for almost two-thirds of the unemployed. The number of unemployed persons who were jobless 5 to 14 weeks rose by 5.2 million to 7.0 million. The number of long-term unemployed (those jobless for 27 weeks or more), at 939,000, declined by 225,000 over the month and represented 4.1 percent of the unemployed. (See table A-12.)

The labor force participation rate decreased by 2.5 percentage points over the month to 60.2 percent, the lowest rate since January 1973 (when it was 60.0 percent). Total employment, as measured by the household survey, fell by 22.4 million to 133.4 million. The employment-population ratio, at 51.3 percent, dropped by 8.7 percentage points over the month. This is the lowest rate and largest over-the-month decline in the history of the series (seasonally adjusted data are available back to January 1948). (See table A-1.)

The number of persons who usually work full time declined by 15.0 million over the month, and the number who usually work part time declined by 7.4 million. Part-time workers accounted for one-third of the over-the-month employment decline. (See table A-9.)

The number of persons at work part time for economic reasons nearly doubled over the month to 10.9 million. These individuals, who would have preferred full-time employment, were working part time because their hours had been reduced or they were unable to find full-time jobs. This group includes persons who usually work full time and persons who usually work part time. (See table A-8.)

The number of persons not in the labor force who currently want a job, at 9.9 million, nearly doubled in April. These individuals were not counted as unemployed because they were not actively looking for work during the last 4 weeks or were unavailable to take a job. (See table A-1.)

Persons marginally attached to the labor force--a subset of persons not in the labor force who currently want a

job--numbered 2.3 million in April, up by 855,000 over the month. These individuals were not in the labor force, wanted and were available for work, and had looked for a job sometime in the prior 12 months but had not looked for work in the 4 weeks preceding the survey. Discouraged workers, a subset of the marginally attached who believed that no jobs were available for them, numbered 574,000 in April, little changed from the previous month. (See Summary table A.)

Establishment Survey Data

Total nonfarm payroll employment fell by 20.5 million in April, after declining by 881,000 in March. The April over-the-month decline is the largest in the history of the series and brought employment to its lowest level since January 2011 (the series dates back to 1939). Job losses in April were widespread, with the largest employment decline occurring in leisure and hospitality. (See table B-1. For more information about how the establishment survey and its measures were affected by the coronavirus, see the box note at the end of the news release.)

In April, employment in leisure and hospitality plummeted by 7.7 million, or 47 percent. Almost three-quarters of the decrease occurred in food services and drinking places (-5.5 million). Employment also fell in the arts, entertainment, and recreation industry (-1.3 million) and in the accommodation industry (-839,000).

Employment declined by 2.5 million in education and health services in April. In health care, employment declined by 1.4 million, led by losses in offices of dentists (-503,000), offices of physicians (-243,000), and offices of other health care practitioners (-205,000). Employment also declined in social assistance (-651,000), reflecting job losses in child day care services (-336,000) and individual and family services (-241,000). Employment in private education declined by 457,000 over the month.

Professional and business services shed 2.2 million jobs in April. Sharp losses occurred in temporary help services (-842,000) and in services to buildings and dwellings (-259,000).

In April, employment in retail trade declined by 2.1 million. Job losses occurred in clothing and clothing accessories stores (-740,000), motor vehicle and parts dealers (-345,000), miscellaneous store retailers (-264,000), and furniture and home furnishings stores (-209,000). By contrast, the component of general merchandise stores that includes warehouse clubs and supercenters gained 93,000 jobs.

In April, manufacturing employment dropped by 1.3 million. About two-thirds of the decline was in durable goods manufacturing (-914,000), which saw losses in motor vehicles and parts (-382,000) and in fabricated metal products (-109,000). Nondurable goods manufacturing shed 416,000 jobs.

Employment in the other services industry declined by 1.3 million in April, with nearly two-thirds of the decline occurring in personal and laundry services (-797,000).

Government employment dropped by 980,000 in April. Employment in local government was down by 801,000, in part reflecting school closures. Employment also declined in state government education (-176,000).

Construction employment fell by 975,000 in April, with much of the loss in specialty trade contractors (-691,000). Job losses also occurred in construction of buildings (-206,000).

Employment fell in transportation and warehousing in April (-584,000). Transit and ground passenger transportation and air transportation lost 185,000 jobs and 141,000 jobs, respectively.

Wholesale trade shed 363,000 jobs in April, largely reflecting losses in the durable and nondurable goods components.

Employment in financial activities fell by 262,000 over the month, with the vast majority of the decline occurring in real estate and rental and leasing (-222,000).

Employment in information fell by 254,000 in April, driven by a decline in motion picture and sound recording industries (-217,000).

Mining lost 46,000 jobs in April, with most of the decline occurring in support activities for mining (-33,000).

In April, average hourly earnings for all employees on private nonfarm payrolls increased by $1.34 to $30.01. Average hourly earnings of private-sector production and nonsupervisory employees increased by $1.04 to $25.12 in April. The increases in average hourly earnings largely reflect the substantial job loss among lower-paid workers; this change, along with earnings increases, put upward pressure on the average hourly earnings estimates. (See tables B-3 and B-8.)

The average workweek for all employees on private nonfarm payrolls increased by 0.1 hour to 34.2 hours in April. In manufacturing, the workweek declined by 2.1 hours to 38.3 hours, and overtime declined by 0.9 hour to 2.1 hours. The average workweek for production and nonsupervisory employees on private nonfarm payrolls increased by 0.1 hour to 33.5 hours. (See tables B-2 and B-7.)

The change in total nonfarm payroll employment for February was revised down by 24,000 from +275,000 to +251,000, and the change for March was revised down by 180,000 from -701,000 to -881,000. With these revisions, employment changes in February and March combined were 204,000 lower than previously reported. (Monthly revisions result from additional reports received from businesses and government agencies since the last published estimates and from the recalculation of seasonal factors.)

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The Employment Situation for May is scheduled to be released on Friday, June 5, 2020, at 8:30 a.m. (EDT).

Coronavirus (COVID-19) Impact on April 2020 Establishment and Household Survey Data
Data collection for both surveys was affected by the coronavirus (COVID-19) pandemic. The household survey is generally collected through in-person and telephone interviews, but personal interviews were not conducted for the safety of interviewers and respondents. The household survey response

rate, at 70 percent, was about 13 percentage points lower than in months prior to the pandemic. In the establishment survey, approximately one-fifth of the data is collected at four regional data collection centers. Although these centers were closed, about half of the interviewers at these centers worked remotely to collect data by telephone. Additionally, BLS encouraged businesses to report electronically. The collection rate for the establishment survey in April was 74.9 percent, essentially unchanged from collection rates prior to the pandemic.

In the establishment survey, workers who are paid by their employer for all or any part of the pay period including the 12th of the month are counted as employed, even if they were not actually at their jobs. Workers who are temporarily or permanently absent from their jobs and are not being paid are not counted as employed, even if they are continuing to receive benefits. The length of the reference period does vary across the respondents in the establishment survey; one-third of businesses have a weekly pay period, slightly over 40 percent a bi-weekly, about 20 percent semi-monthly, and a small amount monthly.

There was a change to the estimation method used in the establishment survey for April. Business births and deaths cannot be adequately captured by the establishment survey as they occur. Therefore, the establishment survey estimates use a model to account for the relatively stable net employment change generated by business births and deaths. Due to the impact of the COVID-19 pandemic, the relationship between the two was no longer stable in April. Therefore, the establishment survey made modifications to the birth-death model. For more information, see www.bls.gov/cps/employment-situation-covid19-faq-april-2020.pdf.

In the household survey, individuals are classified as employed, unemployed, or not in the labor force based on their answers to a series of questions about their activities during the survey reference week (April 12th through April 18th). Workers who indicate they were not working during the entire survey reference week and expect to be recalled to their jobs should be classified as unemployed on temporary layoff. In April, there was an extremely large increase in the number of persons classified as unemployed on temporary layoff.

However, there was also a large increase in the number of workers who were classified as employed but absent from work. As was the case in March, special instructions sent to household survey interviewers called for all employed persons absent from work due to coronavirus-related business closures to be classified as unemployed on temporary layoff. However, it is apparent that not all such workers were so classified.

If the workers who were recorded as employed but absent from work due to "other reasons" (over and above the number absent for other reasons in a typical April) had been classified as unemployed on temporary layoff, the overall unemployment rate would have been almost 5 percentage points higher than reported (on a not seasonally adjusted basis). However, according to usual practice, the data from the household survey are accepted as recorded. To maintain data integrity, no ad hoc actions are taken to reclassify survey responses.

More information is available at www.bls.gov/cps/employment-situation-covid19-faq-april-2020.pdf.

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- Employment Situation Summary Table B. Establishment data, seasonally adjusted
- Employment Situation Frequently Asked Questions
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- Table A-2. Employment status of the civilian population by race, sex, and age
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- Access to historical data for the "A" tables of the Employment Situation News Release
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News Release

EMBARGOED UNTIL RELEASE AT 8:30 A.M. EDT, WEDNESDAY, APRIL 29, 2020 BEA 20-19

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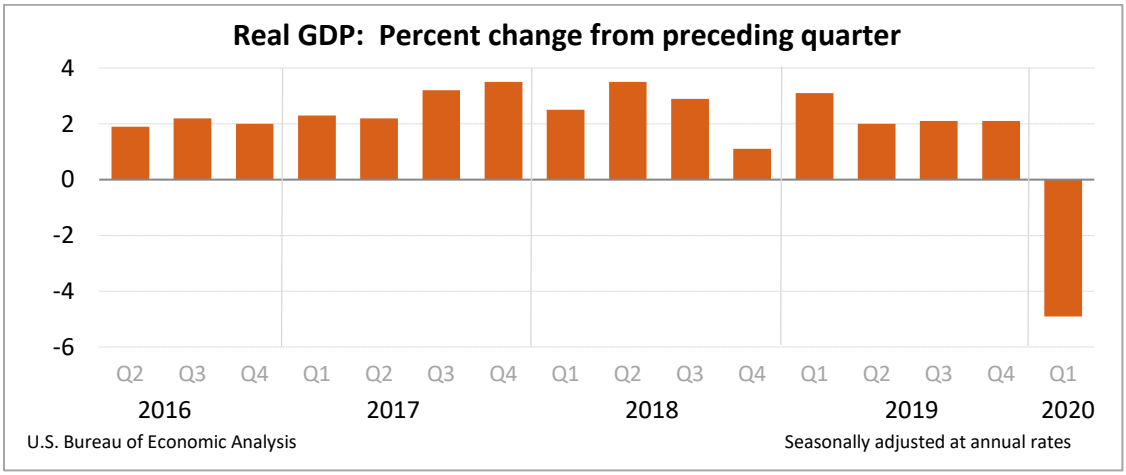
Gross Domestic Product, First Quarter 2020 (Advance Estimate)

Real gross domestic product (GDP) decreased at an annual rate of 4.8 percent in the first quarter of 2020 (table 1), according to the "advance" estimate released by the Bureau of Economic Analysis. In the fourth quarter of 2019, real GDP increased 2.1 percent.

The GDP estimate released today is based on source data that are incomplete or subject to further revision by the source agency (see “Source Data for the Advance Estimate” on page 2). The "second" estimate for the first quarter, based on more complete data, will be released on May 28, 2020.



Coronavirus (COVID-19) Impact on the Advance First-Quarter 2020 GDP Estimate

The decline in first quarter GDP was, in part, due to the response to the spread of COVID-19, as governments issued “stay-at-home” orders in March. This led to rapid changes in demand, as businesses and schools switched to remote work or canceled operations, and consumers canceled, restricted, or redirected their spending. The full economic effects of the COVID-19 pandemic cannot be quantified in the GDP estimate for the first quarter of 2020 because the impacts are generally embedded in source data and cannot be separately identified. For more information, see the Technical Note.

The decrease in **real GDP** in the first quarter reflected negative contributions from personal consumption expenditures (PCE), nonresidential fixed investment, exports, and private inventory investment that were partly offset by positive contributions from residential fixed investment, federal government spending, and state and local government spending. Imports, which are a subtraction in the calculation of GDP, decreased (table 2).

The decrease in PCE reflected decreases in services, led by health care, and goods, led by motor vehicles and parts. The decrease in nonresidential fixed investment primarily reflected a decrease in equipment, led by transportation equipment. The decrease in exports primarily reflected a decrease in services, led by travel.

Current-dollar GDP decreased 3.5 percent, or $191.2 billion, in the first quarter to a level of $21.54 trillion. In the fourth quarter, GDP increased 3.5 percent, or $186.6 billion (tables 1 and 3).

The **price index for gross domestic purchases** increased 1.6 percent in the first quarter, compared with an increase of 1.4 percent in the fourth quarter (table 4). **The PCE price index** increased 1.3 percent, compared with an increase of 1.4 percent. Excluding food and energy prices, the PCE price index increased 1.8 percent, compared with an increase of 1.3 percent.

Personal Income and Outlays

Current-dollar personal income increased $95.2 billion in the first quarter, compared with an increase of $144.1 billion in the fourth quarter. The deceleration was more than accounted for by a deceleration in compensation that was partly offset by an acceleration in personal current transfer receipts (table 8).

Disposable personal income increased $76.7 billion, or 1.9 percent, in the first quarter, compared with an increase of $123.7 billion, or 3.0 percent, in the fourth quarter. **Real disposable personal income** increased 0.5 percent, compared with an increase of 1.6 percent.

Personal outlays decreased $253.5 billion, after increasing $118.8 billion. The decrease was mainly accounted for by a decrease in PCE.

Personal saving was $1.60 trillion in the first quarter, compared with $1.27 trillion in the fourth quarter. The **personal saving rate**—personal saving as a percentage of disposable personal income—was 9.6 percent in the first quarter, compared with 7.6 percent in the fourth quarter.

Source Data for the Advance Estimate

Information on the source data and key assumptions used in the advance estimate is provided in a Technical Note that is posted with the news release on BEA's Web site. A detailed "Key Source Data and Assumptions" file is also posted for each release. For information on updates to GDP, see the "Additional Information" section that follows.

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Upcoming Annual Update of the National Income and Product Accounts

BEA will release results from the 2020 annual update of the National Income and Product Accounts on July 30, 2020, in conjunction with the advance estimate of GDP for the second quarter of 2020. For estimates of real GDP and its major components, the span of the update will cover the most recent five years (2015-2019) and the first quarter of 2020. Estimates of income and saving will be subject to revision from 1999 through the first quarter of 2020. More information on the 2020 annual update will be included in the forthcoming May *Survey of Current Business* article, "GDP and the Economy."

Next release, May 28, 2020 at 8:30 A.M. EDT
Gross Domestic Product, First Quarter 2020 (Second Estimate)
Corporate Profits, First Quarter 2020 (Preliminary Estimate)

* * *

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Additional Information

Resources

Additional resources available at www.bea.gov:

- Information on COVID-19 and recovery impacts are available on our web site.
- Stay informed about BEA developments by reading the BEA blog, signing up for BEA's email subscription service, or following BEA on Twitter @BEA_News.
- Historical time series for these estimates can be accessed in BEA's interactive data application.
- Access BEA data by registering for BEA's data application programming interface (API).
- For more on BEA's statistics, see our monthly online journal, the *Survey of Current Business*.
- BEA's news release schedule
- NIPA Handbook: Concepts and Methods of the U.S. National Income and Product Accounts

Definitions

Gross domestic product (GDP) is the value of the goods and services produced by the nation's economy less the value of the goods and services used up in production. GDP is also equal to the sum of personal consumption expenditures, gross private domestic investment, net exports of goods and services, and government consumption expenditures and gross investment.

Gross domestic income (GDI) is the sum of incomes earned and costs incurred in the production of GDP. In national economic accounting, GDP and GDI are conceptually equal. In practice, GDP and GDI differ because they are constructed using largely independent source data.

Current-dollar estimates are valued in the prices of the period when the transactions occurred—that is, at "market value." Also referred to as "nominal estimates" or as "current-price estimates."

Real values are inflation-adjusted estimates—that is, estimates that exclude the effects of price changes.

The ***gross domestic purchases price index*** measures the prices of final goods and services purchased by U.S. residents.

The ***personal consumption expenditure price index*** measures the prices paid for the goods and services purchased by, or on the behalf of, "persons."

Personal income is the income received by, or on behalf of, all persons from all sources: from participation as laborers in production, from owning a home or business, from the ownership of financial assets, and from government and business in the form of transfers. It includes income from domestic sources as well as the rest of world. It does not include realized or unrealized capital gains or losses.

Disposable personal income is the income available to persons for spending or saving. It is equal to personal income less personal current taxes.

Personal outlays is the sum of personal consumption expenditures, personal interest payments, and personal current transfer payments.

Personal saving is personal income less personal outlays and personal current taxes.

The ***personal saving rate*** is personal saving as a percentage of disposable personal income.

Profits from current production, referred to as corporate profits with inventory valuation adjustment (IVA) and capital consumption adjustment (CCAdj) in the National Income and Product Accounts (NIPAs), is a measure of the net income of corporations before deducting income taxes that is consistent with the value of goods and services measured in GDP. The IVA and CCAdj are adjustments that convert inventory withdrawals and depreciation of fixed assets reported on a tax-return, historical-cost basis to the current-cost economic measures used in the national income and product accounts. Profits for domestic industries reflect profits for all corporations located within the geographic borders of the United States. The rest-of-the-world (ROW) component of profits is measured as the difference between profits received from ROW and profits paid to ROW.

For more definitions, see the Glossary: National Income and Product Accounts.

Statistical conventions

Annual-vs-quarterly rates. Quarterly seasonally adjusted values are expressed at annual rates, unless otherwise specified. This convention is used for BEA's featured, seasonally adjusted measures to facilitate comparisons with related and historical data. For details, see the FAQ "Why does BEA publish estimates at annual rates?" Quarterly not seasonally adjusted values are expressed only at quarterly rates.

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Percent changes. Percent changes in quarterly seasonally adjusted series are displayed at annual rates, unless otherwise specified. For details, see the FAQ "How is average annual growth calculated?" Percent changes in quarterly not seasonally adjusted values are calculated from the same quarter one year ago. All published percent changes are calculated from unrounded data.

Calendar years and quarters. Unless noted otherwise, annual and quarterly data are presented on a calendar basis.

Quantities and prices. Quantities, or "real" volume measures, and prices are expressed as index numbers with a specified reference year equal to 100 (currently 2012). Quantity and price indexes are calculated using a Fisher-chained weighted formula that incorporates weights from two adjacent periods (quarters for quarterly data and annuals for annual data). For details on the calculation of quantity and price indexes, see Chapter 4: Estimating Methods in the NIPA Handbook.

Chained-dollar values are calculated by multiplying the quantity index by the current dollar value in the reference year (2012) and then dividing by 100. Percent changes calculated from real quantity indexes and chained-dollar levels are conceptually the same; any differences are due to rounding. Chained-dollar values are not additive because the relative weights for a given period differ from those of the reference year. In tables that display chained-dollar values, a "residual" line shows the difference between the sum of detailed chained-dollar series and its corresponding aggregate.

Updates to GDP

BEA releases three vintages of the current quarterly estimate for GDP: "Advance" estimates are released near the end of the first month following the end of the quarter and are based on source data that are incomplete or subject to further revision by the source agency; "second" and "third" estimates are released near the end of the second and third months, respectively, and are based on more detailed and more comprehensive data as they become available.

The table below shows the average revisions to the quarterly percent changes in real GDP between different estimate vintages, without regard to sign.

Vintage	Average Revision Without Regard to Sign (percentage points, annual rates)
Advance to second	0.5
Advance to third	0.6
Second to third	0.3
Note - Based on estimates from 1993 through 2018. For more information on GDP updates, see Revision Information on the BEA Web site.	

Annual and comprehensive updates are typically released in late July. Annual updates generally cover at least the 5 most recent calendar years (and their associated quarters) and incorporate newly available major annual source data as well as some changes in methods and definitions to improve the accounts. Comprehensive (or benchmark) updates are carried out at about 5-year intervals and incorporate major periodic source data, as well as major conceptual improvements.

Unlike GDP, an advance current quarterly estimate of GDI is not released because data on domestic profits and on net interest of domestic industries are not available. For fourth quarter estimates, these data are not available until the third estimate.

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Table 1. Real Gross Domestic Product and Related Measures: Percent Change From Preceding Period

Line		2017	2018	2019	Seasonally adjusted at annual rates															Line
					2016			2017				2018				2019				2020	
					Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
1	**Gross domestic product (GDP)**	**2.4**	**2.9**	**2.3**	**1.9**	**2.2**	**2.0**	**2.3**	**2.2**	**3.2**	**3.5**	**2.5**	**3.5**	**2.9**	**1.1**	**3.1**	**2.0**	**2.1**	**2.1**	**-4.8**	1
2	**Personal consumption expenditures**	**2.6**	**3.0**	**2.6**	**2.9**	**2.6**	**2.5**	**2.4**	**2.4**	**2.4**	**4.6**	**1.7**	**4.0**	**3.5**	**1.4**	**1.1**	**4.6**	**3.2**	**1.8**	**-7.6**	2
3	Goods	3.9	4.1	3.7	4.5	4.0	1.9	3.2	5.5	4.1	7.5	1.3	5.4	3.6	1.6	1.5	8.6	5.3	0.6	-1.3	3
4	Durable goods	6.9	6.3	4.8	7.0	10.8	5.8	3.4	7.7	7.8	12.2	2.3	8.0	3.6	1.3	0.3	13.0	8.1	2.8	-16.1	4
5	Nondurable goods	2.5	3.0	3.2	3.2	0.6	0.0	3.1	4.3	2.2	5.1	0.7	4.1	3.6	1.7	2.2	6.5	3.9	-0.6	6.9	5
6	Services	2.0	2.5	2.1	2.2	1.9	2.8	2.0	1.0	1.6	3.4	1.9	3.4	3.4	1.4	1.0	2.8	2.2	2.4	-10.2	6
7	**Gross private domestic investment**	**4.4**	**5.1**	**1.8**	**-1.7**	**0.5**	**9.3**	**3.4**	**3.6**	**7.4**	**4.7**	**6.2**	**-1.8**	**13.7**	**3.0**	**6.2**	**-6.3**	**-1.0**	**-6.0**	**-5.6**	7
8	Fixed investment	4.2	4.6	1.3	2.7	3.8	2.0	7.7	2.8	1.4	8.7	5.5	5.2	0.7	2.7	3.2	-1.4	-0.8	-0.6	-2.6	8
9	Nonresidential	4.4	6.4	2.1	4.0	5.6	0.7	6.6	4.4	2.4	8.4	8.8	7.9	2.1	4.8	4.4	-1.0	-2.3	-2.4	-8.6	9
10	Structures	4.7	4.1	-4.3	10.0	18.4	2.4	7.3	2.0	-7.7	5.2	12.1	11.0	-2.1	-9.0	4.0	-11.1	-9.9	-7.2	-9.7	10
11	Equipment	4.7	6.8	1.3	-2.3	0.3	0.4	6.3	8.9	6.2	12.9	6.6	3.4	2.9	7.4	-0.1	0.8	-3.8	-4.3	-15.2	11
12	Intellectual property products	3.7	7.4	7.5	9.3	4.7	0.0	6.3	0.3	4.9	4.7	9.7	11.9	4.1	11.7	10.8	3.6	4.7	2.8	0.4	12
13	Residential	3.5	-1.5	-1.5	-2.0	-2.6	6.4	11.9	-2.2	-2.0	9.9	-5.3	-3.7	-4.0	-4.7	-1.0	-3.0	4.6	6.5	21.0	13
14	Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	14
15	**Net exports of goods and services**	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	15
16	Exports	3.5	3.0	0.0	4.0	6.1	-2.5	6.1	1.6	4.4	10.1	0.8	5.8	-6.2	1.5	4.1	-5.7	1.0	2.1	-8.7	16
17	Goods	3.9	4.3	0.2	2.7	7.2	-0.8	5.9	2.2	2.2	13.6	1.2	12.0	-9.1	2.6	4.6	-5.9	2.1	-0.6	-1.2	17
18	Services	2.7	0.7	-0.4	6.2	4.1	-5.7	6.3	0.4	8.8	3.8	-0.1	-5.3	-0.1	-0.7	3.3	-5.1	-1.3	7.2	-21.5	18
19	Imports	4.7	4.4	1.0	0.8	4.7	7.5	4.1	3.5	1.3	14.0	0.6	0.3	8.6	3.5	-1.5	0.0	1.8	-8.4	-15.3	19
20	Goods	4.8	5.0	0.3	1.1	3.7	8.1	4.1	3.4	0.9	16.4	1.4	0.8	9.2	2.3	-2.8	0.1	1.1	-11.4	-11.4	20
21	Services	4.4	1.6	4.2	-0.4	9.1	5.2	3.8	4.0	2.8	4.5	-2.8	-2.0	6.1	8.9	4.5	-0.7	4.8	4.9	-29.8	21
22	**Government consumption expenditures and gross investment**	**0.7**	**1.7**	**2.3**	**-0.7**	**1.7**	**1.1**	**-0.2**	**1.4**	**-0.1**	**2.4**	**1.9**	**2.6**	**2.1**	**-0.4**	**2.9**	**4.8**	**1.7**	**2.5**	**0.7**	22
23	Federal	0.8	2.9	3.5	-2.7	2.0	0.6	-1.2	3.3	0.1	4.6	2.8	3.9	2.9	1.1	2.2	8.3	3.3	3.4	1.7	23
24	National defense	0.7	3.3	4.9	-5.2	3.4	-1.0	-1.9	6.8	-1.6	4.5	0.6	7.5	3.0	5.2	7.7	3.3	2.2	4.4	0.8	24
25	Nondefense	0.8	2.4	1.6	1.0	-0.1	2.8	-0.2	-1.6	2.6	4.8	6.0	-1.0	2.8	-4.5	-5.4	16.1	5.0	1.9	3.1	25
26	State and local	0.6	1.0	1.6	0.5	1.6	1.4	0.3	0.3	-0.2	1.1	1.4	1.8	1.6	-1.2	3.3	2.7	0.7	2.0	0.1	26
	Addenda:																				
27	Gross domestic income (GDI) [1]	2.1	2.5	1.9	-1.7	2.0	1.4	3.8	2.6	0.8	2.7	4.7	0.7	3.3	0.8	3.2	0.9	1.2	2.6	.....	27
28	Average of GDP and GDI	2.2	2.7	2.1	0.1	2.1	1.7	3.1	2.4	2.0	3.1	3.6	2.1	3.1	0.9	3.2	1.4	1.7	2.4	.....	28
29	Final sales of domestic product	2.3	2.8	2.2	2.7	2.7	0.8	3.0	2.0	2.2	4.2	2.4	4.8	0.8	1.0	2.6	3.0	2.1	3.1	-4.3	29
30	Gross domestic purchases	2.6	3.1	2.4	1.5	2.1	3.3	2.1	2.4	2.8	4.3	2.5	2.8	4.9	1.4	2.3	2.6	2.2	0.6	-5.9	30
31	Final sales to domestic purchasers	2.5	3.0	2.3	2.2	2.6	2.2	2.8	2.3	1.8	4.9	2.3	4.0	2.8	1.3	1.8	3.6	2.2	1.6	-5.4	31
32	Final sales to private domestic purchasers	2.9	3.3	2.3	2.9	2.8	2.4	3.4	2.5	2.2	5.5	2.4	4.2	2.9	1.7	1.6	3.3	2.3	1.3	-6.6	32
33	Gross national product (GNP)	2.5	3.0	2.4	2.1	1.9	3.0	1.9	1.8	4.0	3.7	2.8	3.1	3.0	0.7	3.1	2.8	2.2	2.2	.....	33
34	Disposable personal income	2.9	4.0	2.9	-0.4	1.8	2.4	4.9	2.7	2.3	3.7	6.9	2.7	3.3	2.8	4.5	1.5	2.1	1.6	0.5	34
	Current-dollar measures:																				
35	GDP	4.3	5.4	4.1	4.7	3.7	4.0	4.2	3.5	5.4	6.4	5.0	7.1	4.8	2.9	3.9	4.7	3.8	3.5	-3.5	35
36	GDI	4.0	5.0	3.7	1.0	3.5	3.3	5.8	4.0	2.9	5.6	7.1	4.2	5.1	2.6	4.1	3.5	3.0	4.0	.....	36
37	Average of GDP and GDI	4.2	5.2	3.9	2.8	3.6	3.7	5.0	3.8	4.1	6.0	6.1	5.6	4.9	2.7	4.0	4.1	3.4	3.7	.....	37
38	Final sales of domestic product	4.3	5.3	4.1	5.3	4.2	3.0	4.9	3.4	4.6	7.0	4.8	8.2	2.8	2.6	3.7	5.4	4.0	4.5	-3.0	38
39	Gross domestic purchases	4.5	5.6	4.0	4.0	3.7	5.1	4.4	3.7	4.5	7.2	5.5	5.6	6.7	3.0	2.8	5.1	3.5	2.0	-4.3	39
40	Final sales to domestic purchasers	4.5	5.5	3.9	4.6	4.2	4.1	5.1	3.6	3.7	7.7	5.3	6.7	4.7	2.8	2.6	5.8	3.7	2.9	-3.8	40
41	Final sales to private domestic purchasers	4.7	5.5	3.8	5.1	4.4	4.3	5.5	3.7	4.0	8.0	5.2	6.7	4.6	2.9	2.2	5.7	3.8	2.6	-5.3	41
42	GNP	4.4	5.5	4.2	4.9	3.4	5.0	3.8	3.1	6.2	6.6	5.2	6.6	4.8	2.5	4.0	5.4	3.9	3.6	.....	42
43	Disposable personal income	4.7	6.1	4.3	2.0	3.5	4.3	7.1	3.6	4.1	6.5	9.6	4.9	4.9	4.2	4.9	3.9	3.6	3.0	1.9	43

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

Source: U.S. Bureau of Economic Analysis

Table 2. Contributions to Percent Change in Real Gross Domestic Product

Line		2017	2018	2019	Seasonally adjusted at annual rates															Line
					2016			2017				2018				2019				2020	
					Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
	Percent change at annual rate:																			
1	**Gross domestic product**	**2.4**	**2.9**	**2.3**	**1.9**	**2.2**	**2.0**	**2.3**	**2.2**	**3.2**	**3.5**	**2.5**	**3.5**	**2.9**	**1.1**	**3.1**	**2.0**	**2.1**	**2.1**	**-4.8**	1
	Percentage points at annual rates:																				
2	**Personal consumption expenditures**	**1.78**	**2.05**	**1.76**	**1.95**	**1.74**	**1.70**	**1.63**	**1.63**	**1.61**	**3.12**	**1.15**	**2.70**	**2.34**	**0.97**	**0.78**	**3.03**	**2.12**	**1.24**	**-5.26**	2
3	**Goods**	**0.83**	**0.86**	**0.78**	**0.94**	**0.84**	**0.41**	**0.68**	**1.14**	**0.85**	**1.55**	**0.27**	**1.13**	**0.75**	**0.33**	**0.32**	**1.74**	**1.09**	**0.12**	**-0.27**	3
4	Durable goods	0.49	0.44	0.34	0.49	0.75	0.41	0.24	0.54	0.55	0.84	0.16	0.56	0.25	0.09	0.02	0.87	0.56	0.20	-1.21	4
5	Motor vehicles and parts	0.13	0.11	0.05	0.14	0.34	0.18	-0.12	0.11	0.23	0.39	-0.15	0.18	0.01	0.07	-0.27	0.37	0.06	0.13	-0.95	5
6	Furnishings and durable household equipment	0.13	0.10	0.05	0.11	0.14	0.06	0.15	0.13	0.15	0.19	0.07	0.08	0.09	-0.09	0.03	0.14	0.10	0.02	-0.11	6
7	Recreational goods and vehicles	0.19	0.16	0.19	0.26	0.22	0.15	0.21	0.25	0.05	0.22	0.17	0.17	0.12	0.04	0.23	0.32	0.31	0.04	0.00	7
8	Other durable goods	0.03	0.08	0.05	-0.02	0.05	0.01	0.00	0.04	0.12	0.04	0.08	0.13	0.03	0.07	0.03	0.04	0.09	0.01	-0.15	8
9	Nondurable goods	0.35	0.42	0.45	0.45	0.09	0.00	0.44	0.60	0.31	0.71	0.11	0.57	0.50	0.24	0.30	0.87	0.53	-0.08	0.94	9
10	Food and beverages purchased for off-premises consumption	0.16	0.16	0.09	0.30	0.12	0.17	0.15	0.09	0.19	0.31	0.12	0.09	0.13	0.07	-0.08	0.25	0.26	-0.06	1.11	10
11	Clothing and footwear	0.02	0.07	0.06	0.02	0.05	-0.09	0.00	0.12	0.00	0.12	-0.03	0.18	0.15	0.00	-0.07	0.25	-0.04	0.09	-0.78	11
12	Gasoline and other energy goods	-0.01	0.00	0.00	-0.05	-0.03	-0.05	-0.04	0.10	-0.04	-0.01	-0.04	0.05	-0.04	0.03	0.01	0.02	-0.02	-0.03	-0.09	12
13	Other nondurable goods	0.18	0.19	0.29	0.18	-0.05	-0.02	0.33	0.29	0.15	0.29	0.06	0.24	0.27	0.14	0.44	0.35	0.33	-0.07	0.70	13
14	**Services**	**0.94**	**1.18**	**0.98**	**1.01**	**0.90**	**1.29**	**0.95**	**0.49**	**0.76**	**1.57**	**0.88**	**1.57**	**1.59**	**0.65**	**0.46**	**1.29**	**1.02**	**1.12**	**-4.99**	14
15	Household consumption expenditures (for services)	0.94	1.08	1.01	1.07	0.57	1.30	0.94	0.61	0.81	1.55	0.78	1.33	1.46	0.24	1.00	1.26	1.04	1.28	-5.61	15
16	Housing and utilities	0.10	0.17	0.12	0.35	0.27	-0.12	-0.13	0.37	0.04	0.33	0.05	0.29	0.07	0.12	0.01	0.14	0.28	0.05	0.08	16
17	Health care	0.27	0.34	0.35	0.84	-0.40	0.80	0.09	-0.03	0.56	0.43	0.20	0.39	0.60	-0.22	0.72	0.38	0.07	0.56	-2.25	17
18	Transportation services	0.08	0.07	0.04	0.02	0.15	0.11	-0.04	0.12	0.13	0.18	0.13	-0.10	-0.02	-0.02	0.01	0.17	0.10	0.02	-0.74	18
19	Recreation services	0.03	0.06	0.07	-0.08	0.12	0.13	0.07	-0.05	-0.05	-0.06	0.16	0.17	0.02	0.09	-0.03	0.17	0.00	0.15	-1.01	19
20	Food services and accommodations	0.12	0.19	0.09	0.04	0.06	0.07	0.33	-0.06	0.11	0.19	0.26	0.23	0.35	-0.12	-0.06	0.22	0.16	0.05	-1.61	20
21	Financial services and insurance	0.10	0.06	0.10	-0.21	0.10	-0.03	0.33	-0.01	0.11	0.14	0.05	-0.04	0.05	0.10	0.15	0.05	0.12	0.20	0.15	21
22	Other services	0.24	0.19	0.26	0.11	0.26	0.33	0.29	0.28	-0.09	0.35	-0.08	0.39	0.38	0.30	0.20	0.13	0.32	0.26	-0.25	22
23	Final consumption expenditures of nonprofit institutions serving households	0.01	0.10	-0.04	-0.06	0.33	-0.02	0.01	-0.12	-0.05	0.02	0.10	0.24	0.13	0.41	-0.54	0.03	-0.02	-0.16	0.63	23
24	Gross output of nonprofit institutions	0.12	0.20	0.18	0.45	0.22	0.32	0.03	-0.23	0.24	0.13	-0.03	0.57	0.45	0.07	0.19	0.14	0.00	0.07	-0.07	24
25	Less: Receipts from sales of goods and services by nonprofit institutions	0.11	0.10	0.22	0.51	-0.11	0.34	0.02	-0.11	0.30	0.11	-0.13	0.33	0.32	-0.34	0.72	0.12	0.02	0.23	-0.69	25
26	**Gross private domestic investment**	**0.75**	**0.87**	**0.32**	**-0.28**	**0.09**	**1.50**	**0.57**	**0.59**	**1.25**	**0.80**	**1.07**	**-0.30**	**2.27**	**0.53**	**1.09**	**-1.16**	**-0.17**	**-1.07**	**-0.96**	26
27	**Fixed investment**	**0.70**	**0.78**	**0.22**	**0.44**	**0.62**	**0.33**	**1.27**	**0.48**	**0.25**	**1.45**	**0.94**	**0.89**	**0.13**	**0.46**	**0.56**	**-0.25**	**-0.14**	**-0.09**	**-0.43**	27
28	Nonresidential	0.57	0.84	0.28	0.52	0.72	0.09	0.84	0.57	0.32	1.08	1.15	1.04	0.29	0.64	0.60	-0.14	-0.31	-0.33	-1.17	28
29	Structures	0.14	0.12	-0.13	0.27	0.50	0.07	0.21	0.06	-0.24	0.15	0.35	0.33	-0.07	-0.29	0.12	-0.36	-0.30	-0.21	-0.28	29
30	Equipment	0.27	0.39	0.08	-0.14	0.02	0.02	0.36	0.50	0.36	0.72	0.39	0.20	0.17	0.42	0.00	0.05	-0.22	-0.25	-0.91	30
31	Information processing equipment	0.18	0.18	0.08	0.05	0.21	0.11	0.18	0.26	0.16	0.28	0.20	0.08	0.20	-0.04	0.17	0.13	-0.13	0.01	-0.30	31
32	Industrial equipment	0.07	0.05	0.01	0.04	-0.02	0.07	0.08	0.14	0.06	0.09	0.07	-0.05	0.07	0.08	-0.04	0.02	0.08	-0.16	-0.08	32
33	Transportation equipment	-0.08	0.09	-0.01	-0.15	-0.19	-0.15	-0.07	-0.08	0.02	0.21	0.12	0.09	-0.07	0.29	-0.06	-0.14	-0.17	-0.01	-0.48	33
34	Other equipment	0.10	0.07	0.00	-0.07	0.02	0.00	0.16	0.18	0.12	0.14	0.00	0.09	-0.03	0.10	-0.08	0.04	0.00	-0.10	-0.04	34
35	Intellectual property products	0.16	0.32	0.34	0.39	0.20	0.00	0.27	0.01	0.21	0.20	0.41	0.51	0.18	0.51	0.48	0.17	0.22	0.13	0.02	35
36	Software	0.14	0.19	0.19	0.12	0.14	0.11	0.19	0.09	0.17	0.10	0.29	0.18	0.15	0.19	0.26	0.11	0.18	0.17	0.16	36
37	Research and development	0.01	0.12	0.14	0.27	0.03	-0.13	0.08	-0.08	0.04	0.07	0.10	0.30	0.01	0.29	0.21	0.06	0.01	-0.05	-0.10	37
38	Entertainment, literary, and artistic originals	0.01	0.02	0.01	0.00	0.04	0.02	0.00	0.00	0.01	0.03	0.02	0.02	0.02	0.03	0.00	0.00	0.02	0.01	-0.03	38
39	Residential	0.13	-0.06	-0.06	-0.07	-0.10	0.24	0.43	-0.09	-0.08	0.37	-0.21	-0.15	-0.16	-0.18	-0.04	-0.11	0.17	0.24	0.74	39
40	**Change in private inventories**	**0.04**	**0.09**	**0.09**	**-0.72**	**-0.53**	**1.18**	**-0.70**	**0.11**	**1.00**	**-0.64**	**0.13**	**-1.20**	**2.14**	**0.07**	**0.53**	**-0.91**	**-0.03**	**-0.98**	**-0.53**	40
41	Farm	0.01	-0.02	0.00	0.18	0.08	-0.12	0.04	0.01	-0.03	0.01	-0.03	-0.02	-0.06	-0.05	0.01	0.04	0.01	0.06	0.10	41
42	Nonfarm	0.03	0.11	0.10	-0.90	-0.61	1.30	-0.74	0.10	1.03	-0.65	0.16	-1.18	2.20	0.12	0.52	-0.95	-0.04	-1.04	-0.63	42
43	**Net exports of goods and services**	**-0.28**	**-0.29**	**-0.15**	**0.35**	**0.05**	**-1.36**	**0.13**	**-0.31**	**0.35**	**-0.80**	**0.00**	**0.67**	**-2.05**	**-0.35**	**0.73**	**-0.68**	**-0.14**	**1.51**	**1.30**	43
44	**Exports**	**0.41**	**0.37**	**0.00**	**0.45**	**0.71**	**-0.30**	**0.72**	**0.20**	**0.54**	**1.19**	**0.10**	**0.71**	**-0.78**	**0.18**	**0.49**	**-0.69**	**0.11**	**0.24**	**-1.02**	44
45	Goods	0.30	0.34	0.02	0.20	0.54	-0.06	0.46	0.18	0.18	1.03	0.11	0.94	-0.78	0.21	0.36	-0.48	0.17	-0.04	-0.08	45
46	Services	0.11	0.03	-0.02	0.25	0.17	-0.24	0.25	0.01	0.36	0.16	0.00	-0.23	0.00	-0.03	0.13	-0.21	-0.05	0.28	-0.93	46
47	**Imports**	**-0.69**	**-0.66**	**-0.15**	**-0.10**	**-0.66**	**-1.06**	**-0.58**	**-0.51**	**-0.18**	**-1.99**	**-0.10**	**-0.04**	**-1.27**	**-0.53**	**0.23**	**0.01**	**-0.26**	**1.27**	**2.32**	47
48	Goods	-0.57	-0.61	-0.04	-0.11	-0.42	-0.92	-0.48	-0.40	-0.10	-1.86	-0.18	-0.10	-1.11	-0.28	0.36	-0.02	-0.13	1.41	1.35	48
49	Services	-0.12	-0.05	-0.12	0.01	-0.24	-0.14	-0.10	-0.11	-0.08	-0.12	0.08	0.06	-0.16	-0.24	-0.13	0.02	-0.13	-0.14	0.96	49
50	**Government consumption expenditures and gross investment**	**0.12**	**0.30**	**0.41**	**-0.12**	**0.31**	**0.19**	**-0.04**	**0.24**	**-0.02**	**0.42**	**0.33**	**0.44**	**0.36**	**-0.07**	**0.50**	**0.82**	**0.30**	**0.44**	**0.13**	50
51	**Federal**	**0.05**	**0.19**	**0.23**	**-0.18**	**0.13**	**0.04**	**-0.08**	**0.21**	**0.01**	**0.30**	**0.18**	**0.25**	**0.19**	**0.07**	**0.14**	**0.53**	**0.22**	**0.22**	**0.12**	51
52	National defense	0.03	0.13	0.19	-0.21	0.13	-0.04	-0.07	0.25	-0.06	0.17	0.02	0.28	0.11	0.20	0.29	0.13	0.09	0.17	0.03	52
53	Consumption expenditures	0.00	0.09	0.14	-0.13	0.16	-0.01	-0.13	0.15	-0.06	0.10	0.02	0.23	0.11	0.07	0.25	0.13	0.01	0.09	0.11	53
54	Gross investment	0.03	0.04	0.05	-0.07	-0.03	-0.02	0.06	0.10	0.00	0.07	0.00	0.05	0.01	0.12	0.04	-0.01	0.08	0.08	-0.08	54
55	Nondefense	0.02	0.07	0.04	0.03	0.00	0.08	0.00	-0.04	0.07	0.13	0.16	-0.03	0.07	-0.12	-0.15	0.40	0.13	0.05	0.08	55
56	Consumption expenditures	0.01	0.06	0.02	0.01	-0.01	0.05	-0.02	-0.06	0.07	0.10	0.18	-0.03	0.05	-0.14	-0.16	0.36	0.10	0.05	0.07	56
57	Gross investment	0.02	0.00	0.02	0.02	0.01	0.02	0.02	0.01	0.00	0.03	-0.02	0.00	0.02	0.02	0.01	0.04	0.03	0.00	0.01	57
58	**State and local**	**0.07**	**0.11**	**0.18**	**0.06**	**0.18**	**0.15**	**0.03**	**0.03**	**-0.02**	**0.12**	**0.15**	**0.19**	**0.17**	**-0.14**	**0.36**	**0.29**	**0.08**	**0.22**	**0.02**	58
59	Consumption expenditures	0.07	0.08	0.10	0.18	0.22	0.06	0.01	0.04	0.07	0.07	0.08	0.10	0.14	0.06	0.10	0.07	0.15	0.11	-0.08	59
60	Gross investment	0.00	0.02	0.08	-0.12	-0.05	0.09	0.02	-0.01	-0.09	0.06	0.07	0.10	0.03	-0.20	0.26	0.23	-0.08	0.11	0.09	60

Source: U.S. Bureau of Economic Analysis

Table 3. Gross Domestic Product: Level and Change From Preceding Period--Continues

Line		Billions of dollars						Billions of chained (2012) dollars								Line
		2019	Seasonally adjusted at annual rates					2019	Seasonally adjusted at annual rates					Change from preceding period		
			2019				2020		2019				2020	2019	2019	2020	
			Q1	Q2	Q3	Q4	Q1		Q1	Q2	Q3	Q4	Q1		Q4	Q1	
1	**Gross domestic product (GDP)**	**21,427.7**	**21,098.8**	**21,340.3**	**21,542.5**	**21,729.1**	**21,537.9**	**19,073.1**	**18,927.3**	**19,021.9**	**19,121.1**	**19,222.0**	**18,987.9**	**434.9**	**100.9**	**-234.1**	1
2	**Personal consumption expenditures**	**14,562.7**	**14,266.3**	**14,511.2**	**14,678.2**	**14,795.0**	**14,555.8**	**13,280.1**	**13,103.3**	**13,250.0**	**13,353.1**	**13,413.8**	**13,153.0**	**335.5**	**60.7**	**-260.8**	2
3	**Goods**	**4,505.0**	**4,397.7**	**4,507.0**	**4,556.7**	**4,558.5**	**4,532.1**	**4,754.6**	**4,649.2**	**4,746.4**	**4,808.0**	**4,814.7**	**4,798.5**	**171.3**	**6.7**	**-16.2**	3
4	Durable goods	1,526.8	1,485.4	1,524.6	1,549.7	1,547.6	1,475.4	1,766.4	1,706.3	1,759.3	1,793.9	1,806.1	1,728.8	80.7	12.2	-77.3	4
5	Motor vehicles and parts	531.2	513.6	533.1	537.1	541.0	488.0	542.7	524.2	544.1	547.5	554.8	501.5	9.6	7.4	-53.3	5
6	Furnishings and durable household equipment	353.7	346.5	352.9	359.0	356.3	352.4	405.7	395.9	404.5	410.5	411.6	404.9	11.5	1.1	-6.7	6
7	Recreational goods and vehicles	417.8	405.9	414.8	426.3	424.0	419.0	569.3	540.5	562.9	585.4	588.3	588.2	53.2	2.8	0.0	7
8	Other durable goods	224.2	219.4	223.8	227.4	226.2	215.9	263.4	258.5	261.1	266.8	267.2	257.3	12.7	0.4	-9.9	8
9	Nondurable goods	2,978.1	2,912.3	2,982.4	3,007.0	3,010.9	3,056.7	3,002.9	2,954.6	3,001.3	3,030.0	3,025.7	3,076.9	93.3	-4.2	51.1	9
10	Food and beverages purchased for off-premises consumption	1,032.2	1,015.4	1,030.1	1,042.8	1,040.6	1,108.9	988.4	973.1	985.8	999.0	995.8	1,053.2	18.1	-3.2	57.4	10
11	Clothing and footwear	398.9	393.5	399.3	402.3	400.6	360.7	407.0	396.7	410.4	408.0	412.8	369.3	12.6	4.9	-43.5	11
12	Gasoline and other energy goods	337.7	321.8	349.3	338.0	341.6	320.9	448.6	449.0	450.1	448.9	446.5	440.2	1.2	-2.5	-6.3	12
13	Other nondurable goods	1,209.3	1,181.6	1,203.6	1,223.9	1,228.1	1,266.2	1,142.1	1,121.2	1,138.9	1,155.8	1,152.3	1,187.7	57.2	-3.5	35.4	13
14	**Services**	**10,057.7**	**9,868.6**	**10,004.2**	**10,121.5**	**10,236.5**	**10,023.7**	**8,562.9**	**8,483.1**	**8,541.4**	**8,587.9**	**8,639.1**	**8,409.5**	**174.8**	**51.2**	**-229.6**	14
15	Household consumption expenditures (for services)	9,612.4	9,426.9	9,558.5	9,670.9	9,793.1	9,543.8	8,201.2	8,119.9	8,177.2	8,224.7	8,283.2	8,024.5	181.5	58.6	-258.7	15
16	Housing and utilities	2,670.4	2,627.7	2,655.9	2,688.1	2,709.8	2,735.6	2,184.3	2,173.1	2,179.1	2,191.4	2,193.4	2,196.9	20.0	2.1	3.5	16
17	Health care	2,470.1	2,426.2	2,459.0	2,476.0	2,519.2	2,409.3	2,249.3	2,227.0	2,245.5	2,248.7	2,275.9	2,165.5	67.7	27.1	-110.3	17
18	Transportation services	478.3	464.7	477.0	483.2	488.1	443.1	438.9	430.3	438.4	443.1	443.9	407.1	6.8	0.8	-36.8	18
19	Recreation services	587.9	574.9	586.1	588.1	602.5	550.6	509.8	502.1	510.0	510.1	517.0	469.7	11.8	6.9	-47.3	19
20	Food services and accommodations	1,019.0	994.9	1,016.1	1,030.0	1,035.0	953.5	858.2	846.5	856.6	863.7	865.9	792.8	15.1	2.2	-73.1	20
21	Financial services and insurance	1,157.0	1,129.4	1,149.1	1,167.1	1,182.4	1,201.8	856.7	850.7	852.7	857.6	865.6	871.6	15.1	8.1	5.9	21
22	Other services	1,229.8	1,209.2	1,215.4	1,238.3	1,256.1	1,250.1	1,123.8	1,108.2	1,114.4	1,129.8	1,142.7	1,130.2	49.5	12.8	-12.5	22
23	Final consumption expenditures of nonprofit institutions serving households	445.3	441.7	445.6	450.6	443.4	479.9	362.4	363.8	364.8	364.0	357.1	384.4	-6.1	-6.9	27.3	23
24	Gross output of nonprofit institutions	1,672.3	1,650.3	1,667.3	1,679.2	1,692.3	1,700.1	1,434.0	1,428.4	1,434.8	1,434.8	1,437.9	1,434.7	32.8	3.2	-3.3	24
25	Less: Receipts from sales of goods and services by nonprofit institutions	1,226.9	1,208.6	1,221.7	1,228.6	1,248.8	1,220.3	1,072.9	1,065.7	1,071.2	1,072.0	1,082.7	1,050.0	40.0	10.7	-32.7	25
26	**Gross private domestic investment**	**3,743.9**	**3,783.4**	**3,749.5**	**3,744.6**	**3,698.3**	**3,659.5**	**3,421.3**	**3,481.1**	**3,424.7**	**3,416.2**	**3,363.4**	**3,314.9**	**60.8**	**-52.8**	**-48.4**	26
27	**Fixed investment**	**3,675.6**	**3,670.1**	**3,674.7**	**3,677.6**	**3,680.2**	**3,668.8**	**3,335.8**	**3,349.4**	**3,337.4**	**3,330.5**	**3,325.9**	**3,304.4**	**42.4**	**-4.6**	**-21.5**	27
28	Nonresidential	2,878.1	2,882.7	2,890.0	2,877.2	2,862.5	2,806.8	2,748.1	2,765.6	2,758.5	2,742.7	2,725.7	2,664.9	55.8	-16.9	-60.8	28
29	Structures	627.0	645.8	633.2	619.4	609.6	596.6	517.8	538.6	523.0	509.6	500.1	487.5	-23.1	-9.4	-12.6	29
30	Equipment	1,241.0	1,249.0	1,252.9	1,237.4	1,224.7	1,177.2	1,271.3	1,278.9	1,281.5	1,269.3	1,255.6	1,204.7	16.1	-13.7	-50.8	30
31	Information processing equipment	412.7	416.0	419.0	409.2	406.8	389.7	517.9	515.4	524.1	515.5	516.5	495.4	19.4	1.0	-21.1	31
32	Industrial equipment	252.5	250.8	252.4	257.3	249.3	245.6	241.1	240.4	241.4	245.3	237.2	232.9	2.5	-8.1	-4.3	32
33	Transportation equipment	301.8	309.4	306.0	294.8	297.2	272.9	277.2	286.6	279.7	271.5	271.1	247.4	-2.9	-0.4	-23.7	33
34	Other equipment	274.0	272.9	275.5	276.1	271.6	269.0	251.3	251.2	253.1	252.9	248.1	245.9	0.5	-4.8	-2.2	34
35	Intellectual property products	1,010.1	987.9	1,003.9	1,020.5	1,028.2	1,033.0	969.2	955.6	964.2	975.2	982.0	983.1	67.7	6.8	1.1	35
36	Software	415.5	404.1	411.4	421.1	425.4	432.8	455.6	443.0	449.3	460.0	470.3	479.7	42.2	10.3	9.4	36
37	Research and development	501.6	492.0	499.9	505.8	508.5	507.1	434.5	432.6	435.5	436.2	433.7	429.0	25.3	-2.4	-4.8	37
38	Entertainment, literary, and artistic originals	93.1	91.8	92.6	93.6	94.3	93.1	85.9	85.4	85.3	86.2	86.7	85.1	2.6	0.5	-1.6	38
39	Residential	797.5	787.4	784.7	800.3	817.7	862.0	593.8	591.4	587.0	593.7	603.1	632.6	-9.1	9.4	29.5	39
40	**Change in private inventories**	**68.3**	**113.3**	**74.8**	**67.0**	**18.0**	**-9.3**	**67.0**	**116.0**	**69.4**	**69.4**	**13.1**	**-16.3**	**18.8**	**-56.4**	**-29.4**	40
41	Farm	-7.6	-10.1	-8.2	-7.6	-4.3	0.6	-11.1	-14.2	-11.0	-11.3	-7.7	-0.8	-2.1	3.6	6.9	41
42	Nonfarm	75.9	123.4	83.0	74.7	22.3	-9.9	75.3	126.6	77.9	77.6	19.0	-15.4	20.1	-58.6	-34.4	42
43	**Net exports of goods and services**	**-631.9**	**-633.8**	**-662.7**	**-653.0**	**-577.9**	**-527.9**	**-953.9**	**-944.0**	**-980.7**	**-990.1**	**-900.7**	**-817.4**	**-33.8**	**89.4**	**83.3**	43
44	**Exports**	**2,504.3**	**2,520.3**	**2,504.0**	**2,495.1**	**2,497.7**	**2,422.7**	**2,532.9**	**2,554.4**	**2,517.5**	**2,523.4**	**2,536.4**	**2,479.5**	**0.0**	**12.9**	**-56.9**	44
45	Goods	1,643.8	1,661.8	1,646.1	1,638.0	1,629.2	1,601.6	1,786.2	1,802.6	1,775.3	1,784.7	1,782.3	1,776.9	3.5	-2.5	-5.3	45
46	Services	860.5	858.5	858.0	857.1	868.5	821.1	752.5	757.8	748.0	745.5	758.6	714.2	-2.9	13.1	-44.4	46
47	**Imports**	**3,136.1**	**3,154.1**	**3,166.7**	**3,148.2**	**3,075.6**	**2,950.6**	**3,486.8**	**3,498.3**	**3,498.2**	**3,513.6**	**3,437.1**	**3,296.9**	**33.8**	**-76.5**	**-140.1**	47
48	Goods	2,530.1	2,554.3	2,566.1	2,540.9	2,459.0	2,386.4	2,923.4	2,940.7	2,941.7	2,949.6	2,861.5	2,776.4	7.3	-88.1	-85.1	48
49	Services	606.1	599.8	600.6	607.2	616.6	564.2	562.4	558.1	557.2	563.7	570.4	522.1	22.4	6.8	-48.4	49

1. Real gross domestic income is gross domestic income deflated by the implicit price deflator for gross domestic product.

Note. Users are cautioned that particularly for components that exhibit rapid change in prices relative to other prices in the economy, the chained-dollar estimates should not be used to measure the component's relative importance or its contribution to the growth rate of more aggregate series. For accurate estimates of the contributions to percent changes in real gross domestic product, use table 2.

Source: U.S. Bureau of Economic Analysis

Table 3. Gross Domestic Product: Level and Change From Preceding Period--Table Ends

Line		Billions of dollars						Billions of chained (2012) dollars									Line
		2019	Seasonally adjusted at annual rates					2019	Seasonally adjusted at annual rates					Change from preceding period			
			2019				2020		2019				2020	2019	2019	2020	
			Q1	Q2	Q3	Q4	Q1		Q1	Q2	Q3	Q4	Q1		Q4	Q1	
50	**Government consumption expenditures and gross investment**	**3,753.0**	**3,683.1**	**3,742.3**	**3,772.8**	**3,813.7**	**3,850.5**	**3,299.0**	**3,258.1**	**3,296.6**	**3,310.4**	**3,331.1**	**3,337.0**	**75.2**	**20.7**	**5.9**	50
51	**Federal**	**1,423.0**	**1,394.7**	**1,415.2**	**1,432.2**	**1,449.8**	**1,459.8**	**1,275.5**	**1,248.8**	**1,273.9**	**1,284.4**	**1,295.1**	**1,300.6**	**43.3**	**10.7**	**5.5**	51
52	National defense	846.2	831.8	841.6	849.3	862.1	866.1	773.4	764.5	770.8	775.0	783.3	784.8	35.9	8.3	1.5	52
53	Consumption expenditures	677.8	666.6	676.9	680.2	687.6	695.7	613.7	607.6	614.1	614.5	618.7	624.0	25.9	4.2	5.3	53
54	Gross investment	168.4	165.2	164.8	169.1	174.5	170.3	159.9	157.1	156.8	160.7	165.0	161.0	10.1	4.3	-4.0	54
55	Nondefense	576.8	562.9	573.5	583.0	587.7	593.8	502.0	484.5	502.9	509.1	511.5	515.4	7.8	2.4	3.9	55
56	Consumption expenditures	436.2	425.0	433.6	440.9	445.1	450.1	373.2	358.0	374.2	379.1	381.3	384.6	4.1	2.2	3.3	56
57	Gross investment	140.6	137.9	139.9	142.1	142.6	143.7	128.9	126.7	128.6	130.0	130.2	130.7	3.8	0.2	0.6	57
58	**State and local**	**2,330.0**	**2,288.4**	**2,327.1**	**2,340.5**	**2,363.9**	**2,390.7**	**2,022.3**	**2,007.9**	**2,021.4**	**2,024.9**	**2,035.0**	**2,035.6**	**32.3**	**10.1**	**0.6**	58
59	Consumption expenditures	1,904.5	1,876.4	1,897.9	1,913.2	1,930.4	1,950.6	1,654.6	1,647.5	1,650.5	1,657.7	1,662.8	1,659.1	18.0	5.2	-3.8	59
60	Gross investment	425.5	412.0	429.2	427.4	433.4	440.1	367.6	360.3	370.8	367.2	372.1	376.4	14.3	4.9	4.3	60
61	Residual	.....	.....	.....	.....	.....	.....	-68.6	-51.4	-62.3	-74.8	-85.8	-83.4	.....	.....	.....	61
	Addenda:																
62	Gross domestic income (GDI) [1]	21,322.6	21,056.7	21,237.8	21,393.1	21,602.9	.....	18,979.5	18,889.5	18,930.5	18,988.4	19,110.3	.....	351.1	121.8	.....	62
63	Average of GDP and GDI	21,375.2	21,077.8	21,289.0	21,467.8	21,666.0	.....	19,026.3	18,908.4	18,976.2	19,054.8	19,166.1	.....	393.0	111.4	.....	63
64	Final sales of domestic product	21,359.4	20,985.5	21,265.5	21,475.5	21,711.1	21,547.2	18,987.9	18,797.5	18,935.2	19,035.7	19,183.2	18,975.4	416.6	147.5	-207.8	64
65	Gross domestic purchases	22,059.5	21,732.7	22,002.9	22,195.6	22,307.0	22,065.9	19,994.6	19,836.1	19,965.4	20,073.7	20,103.1	19,802.1	471.3	29.4	-301.0	65
66	Final sales to domestic purchasers	21,991.2	21,619.4	21,928.1	22,128.5	22,289.0	22,075.1	19,909.7	19,705.7	19,878.9	19,988.6	20,065.6	19,791.4	452.9	77.0	-274.2	66
67	Final sales to private domestic purchasers	18,238.3	17,936.3	18,185.9	18,355.8	18,475.3	18,224.6	16,615.5	16,452.7	16,587.1	16,683.1	16,739.2	16,457.0	377.7	56.0	-282.2	67
68	**Gross domestic product**	**21,427.7**	**21,098.8**	**21,340.3**	**21,542.5**	**21,729.1**	**21,537.9**	**19,073.1**	**18,927.3**	**19,021.9**	**19,121.1**	**19,222.0**	**18,987.9**	**434.9**	**100.9**	**-234.1**	68
69	Plus: Income receipts from the rest of the world	1,158.8	1,149.0	1,177.2	1,160.4	1,148.7	.....	1,053.0	1,051.1	1,071.0	1,052.0	1,037.9	.....	29.1	-14.0	.....	69
70	Less: Income payments to the rest of the world	863.3	891.2	876.2	851.4	834.5	.....	772.8	802.9	785.3	760.3	742.7	.....	10.3	-17.6	.....	70
71	**Equals: Gross national product**	**21,723.2**	**21,356.7**	**21,641.3**	**21,851.5**	**22,043.4**	.....	**19,351.3**	**19,173.6**	**19,305.2**	**19,410.8**	**19,515.5**	.....	**453.5**	**104.7**	.....	71
72	Net domestic product	17,964.7	17,696.7	17,893.8	18,056.7	18,211.9	17,986.2	15,950.6	15,841.7	15,911.1	15,986.1	16,063.6	15,809.2	338.0	77.6	-254.4	72

1. Real gross domestic income is gross domestic income deflated by the implicit price deflator for gross domestic product.

Note. Users are cautioned that particularly for components that exhibit rapid change in prices relative to other prices in the economy, the chained-dollar estimates should not be used to measure the component's relative importance or its contribution to the growth rate of more aggregate series. For accurate estimates of the contributions to percent changes in real gross domestic product, use table 2.

Source: U.S. Bureau of Economic Analysis

April 29, 2020

Table 4. Price Indexes for Gross Domestic Product and Related Measures: Percent Change From Preceding Period

Line		2017	2018	2019	Seasonally adjusted at annual rates																Line
					2016			2017				2018				2019				2020	
					Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
1	**Gross domestic product (GDP)**	**1.9**	**2.4**	**1.8**	**2.6**	**1.4**	**2.1**	**1.9**	**1.3**	**2.4**	**2.6**	**2.3**	**3.2**	**2.0**	**1.6**	**1.1**	**2.4**	**1.8**	**1.3**	**1.3**	1
2	**Personal consumption expenditures**	**1.8**	**2.1**	**1.4**	**2.4**	**1.7**	**1.8**	**2.1**	**0.9**	**1.7**	**2.7**	**2.5**	**2.2**	**1.6**	**1.3**	**0.4**	**2.4**	**1.5**	**1.4**	**1.3**	2
3	Goods	0.3	0.7	-0.5	1.2	-1.0	0.7	2.2	-2.6	0.7	1.4	2.0	0.7	-0.3	-1.4	-1.6	1.6	-0.8	-0.4	-1.0	3
4	Durable goods	-2.3	-1.7	-1.2	-2.8	-3.8	-3.4	0.3	-3.4	-2.6	-1.8	-1.1	-1.7	-1.2	-1.1	-0.3	-1.8	-1.2	-3.2	-1.6	4
5	Nondurable goods	1.6	1.9	-0.1	3.3	0.5	2.9	3.1	-2.2	2.4	3.1	3.6	2.0	0.1	-1.5	-2.3	3.3	-0.5	1.1	-0.6	5
6	Services	2.4	2.7	2.3	2.9	2.9	2.3	2.1	2.6	2.1	3.2	2.8	2.9	2.5	2.6	1.3	2.8	2.5	2.2	2.4	6
7	**Gross private domestic investment**	**1.7**	**2.3**	**1.6**	**1.5**	**0.8**	**2.1**	**1.6**	**2.2**	**2.4**	**0.8**	**3.4**	**2.8**	**2.1**	**0.7**	**1.7**	**2.0**	**1.1**	**0.8**	**1.2**	7
8	Fixed investment	1.7	2.3	1.6	1.4	0.8	2.1	1.7	2.2	2.1	1.2	3.3	3.0	2.1	0.5	1.8	2.0	1.2	0.8	1.4	8
9	Nonresidential	1.0	1.4	1.2	0.4	-0.6	1.2	1.2	1.4	1.4	0.7	1.7	1.9	1.6	0.0	1.6	2.0	0.5	0.4	1.2	9
10	Structures	2.7	3.6	3.4	3.1	-0.5	2.2	2.9	4.1	4.5	2.2	2.9	5.0	3.2	5.6	2.8	4.0	1.6	1.1	1.6	10
11	Equipment	-0.2	0.1	0.2	-0.9	-0.9	-1.2	1.1	0.1	-0.2	-0.4	-0.3	0.8	1.6	-1.1	1.0	0.4	-1.1	0.2	0.7	11
12	Intellectual property products	1.3	1.5	0.9	0.2	-0.3	3.8	0.4	1.4	1.3	1.2	3.7	1.1	0.5	-2.2	1.5	2.9	2.0	0.2	1.4	12
13	Residential	4.5	5.6	2.9	5.3	6.1	5.3	3.1	5.1	4.6	3.0	9.1	7.0	3.9	2.5	2.6	1.7	3.4	2.4	2.0	13
14	Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	14
15	**Net exports of goods and services**	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	15
16	Exports	2.6	3.4	-0.2	4.1	2.4	2.7	2.6	0.2	3.8	5.5	3.5	5.1	1.1	-1.4	-2.5	3.3	-2.3	-1.6	-3.1	16
17	Goods	2.6	3.6	-1.2	5.5	2.2	1.9	3.0	-0.7	5.0	5.5	3.8	5.9	0.9	-2.8	-4.0	2.4	-4.0	-1.6	-5.5	17
18	Services	2.6	3.0	1.7	1.6	2.8	4.3	1.9	1.8	1.4	5.6	3.0	3.5	1.5	1.4	0.5	5.1	0.9	-1.7	1.7	18
19	Imports	2.2	2.9	-1.4	1.7	2.9	1.2	4.7	-0.3	0.6	5.2	7.3	0.6	0.6	-1.8	-3.5	1.6	-4.0	-0.5	0.1	19
20	Goods	2.3	2.9	-1.8	1.7	3.6	1.4	5.6	-1.3	-0.3	5.8	8.1	0.2	0.4	-2.3	-4.3	1.7	-4.9	-1.0	0.1	20
21	Services	2.0	3.0	0.7	1.6	-0.1	0.7	1.2	4.1	4.6	2.9	3.9	2.2	1.3	0.8	-0.2	1.3	-0.2	1.4	-0.1	21
22	**Government consumption expenditures and gross investment**	**2.5**	**3.5**	**2.1**	**2.9**	**1.5**	**2.1**	**3.3**	**1.5**	**2.8**	**4.2**	**4.0**	**3.8**	**3.0**	**2.9**	**1.3**	**1.7**	**1.6**	**1.8**	**3.2**	22
23	Federal	2.1	3.1	2.0	2.3	1.7	1.9	2.2	1.7	2.0	3.3	4.4	2.9	2.6	2.8	4.6	-2.1	1.5	1.6	1.1	23
24	National defense	1.7	3.0	1.7	2.4	1.6	1.5	1.8	1.1	1.7	3.1	4.5	2.8	2.7	1.8	1.1	1.5	1.4	1.7	1.1	24
25	Nondefense	2.6	3.3	2.6	2.1	1.9	2.6	2.8	2.6	2.5	3.5	4.2	3.0	2.4	4.3	10.0	-7.2	1.7	1.4	1.0	25
26	State and local	2.7	3.7	2.2	3.2	1.3	2.3	3.9	1.4	3.3	4.7	3.7	4.4	3.3	2.9	-0.6	4.1	1.6	2.0	4.5	26
	Addenda:																				
27	Final sales of domestic product	1.9	2.4	1.8	2.6	1.4	2.1	1.9	1.3	2.3	2.6	2.3	3.2	2.0	1.6	1.1	2.4	1.8	1.3	1.3	27
28	Gross domestic purchases	1.9	2.4	1.5	2.3	1.5	1.9	2.2	1.2	2.0	2.6	2.9	2.6	1.9	1.5	0.8	2.2	1.4	1.4	1.6	28
29	Final sales to domestic purchasers	1.9	2.4	1.5	2.3	1.5	1.9	2.2	1.2	1.9	2.7	2.9	2.6	1.9	1.5	0.8	2.2	1.4	1.4	1.7	29
30	Final sales to private domestic purchasers	1.8	2.1	1.4	2.2	1.5	1.9	2.0	1.2	1.7	2.4	2.7	2.4	1.7	1.2	0.7	2.3	1.4	1.3	1.3	30
31	Gross national product (GNP)	1.9	2.4	1.8	2.6	1.4	2.1	1.8	1.3	2.4	2.5	2.2	3.2	2.0	1.6	1.1	2.4	1.8	1.3	.....	31
32	GDP excluding food and energy [1]	1.9	2.5	1.9	2.2	1.9	2.0	2.0	1.4	2.0	2.6	2.8	3.0	2.1	2.0	1.4	2.3	1.9	1.3	2.0	32
33	Gross domestic purchases excluding food and energy [1]	1.8	2.3	1.7	2.0	1.7	1.7	1.9	1.5	1.9	2.3	2.8	2.6	2.0	1.7	1.2	1.8	1.8	1.3	1.9	33
34	PCE excluding food and energy [1]	1.6	1.9	1.6	2.0	2.0	1.4	1.7	1.3	1.5	2.2	2.3	2.1	1.6	1.7	1.1	1.9	2.1	1.3	1.8	34
35	Market-based PCE [2]	1.5	1.8	1.3	2.1	1.4	1.6	2.1	0.2	1.4	2.4	2.3	2.1	1.3	1.1	0.8	2.1	1.1	1.3	1.2	35
36	Market-based PCE excluding food and energy [1,2]	1.3	1.6	1.6	1.6	1.6	1.2	1.6	0.5	1.1	1.7	2.0	2.0	1.2	1.6	1.7	1.4	1.8	1.1	1.7	36
	Implicit price deflators:																				
37	GDP	1.9	2.4	1.7	2.8	1.5	1.9	1.9	1.3	2.1	2.8	2.4	3.4	1.8	1.8	0.8	2.6	1.7	1.4	1.4	37
38	Gross domestic purchases	1.9	2.4	1.5	2.4	1.6	1.7	2.2	1.2	1.7	2.8	3.0	2.8	1.7	1.6	0.5	2.4	1.3	1.4	1.7	38
39	GNP	1.9	2.4	1.8	2.8	1.5	1.9	1.8	1.3	2.1	2.7	2.3	3.4	1.8	1.8	0.8	2.6	1.7	1.4	.....	39

1. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

2. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Source: U.S. Bureau of Economic Analysis

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Table 5. Real Gross Domestic Product: Annual Percent Change

Line		Percent change from preceding year								Percent change from fourth quarter to fourth quarter one year ago								Line
		2012	2013	2014	2015	2016	2017	2018	2019	2012	2013	2014	2015	2016	2017	2018	2019	
1	**Gross domestic product (GDP)**	**2.2**	**1.8**	**2.5**	**2.9**	**1.6**	**2.4**	**2.9**	**2.3**	**1.5**	**2.6**	**2.9**	**1.9**	**2.0**	**2.8**	**2.5**	**2.3**	1
2	**Personal consumption expenditures (PCE)**	**1.5**	**1.5**	**3.0**	**3.7**	**2.7**	**2.6**	**3.0**	**2.6**	**1.6**	**1.9**	**3.8**	**2.9**	**2.8**	**2.9**	**2.6**	**2.7**	2
3	Goods	2.1	3.1	4.1	4.7	3.6	3.9	4.1	3.7	2.4	3.5	5.0	3.7	3.6	5.0	2.9	3.9	3
4	Durable goods	6.0	6.1	7.2	7.5	6.1	6.9	6.3	4.8	6.3	5.0	9.2	5.8	7.3	7.7	3.8	5.9	4
5	Nondurable goods	0.4	1.8	2.6	3.4	2.4	2.5	3.0	3.2	0.7	2.8	3.2	2.8	1.8	3.7	2.5	3.0	5
6	Services	1.2	0.6	2.4	3.2	2.3	2.0	2.5	2.1	1.2	1.1	3.2	2.5	2.4	2.0	2.5	2.1	6
7	**Gross private domestic investment**	**11.0**	**6.9**	**5.6**	**4.9**	**-1.3**	**4.4**	**5.1**	**1.8**	**4.0**	**9.3**	**5.3**	**1.5**	**1.5**	**4.8**	**5.1**	**-1.9**	7
8	Fixed investment	10.0	5.6	6.6	3.4	1.9	4.2	4.6	1.3	7.2	5.7	7.0	1.0	2.8	5.1	3.5	0.1	8
9	Nonresidential	9.5	4.1	7.2	1.8	0.7	4.4	6.4	2.1	5.6	5.4	6.9	-0.9	2.4	5.4	5.9	-0.4	9
10	Structures	13.0	1.3	11.0	-3.0	-5.0	4.7	4.1	-4.3	4.0	6.7	9.3	-10.9	4.3	1.5	2.6	-6.2	10
11	Equipment	11.0	4.7	7.0	3.2	-1.3	4.7	6.8	1.3	7.8	5.4	5.6	1.9	-1.4	8.5	5.0	-1.8	11
12	Intellectual property products	5.0	5.4	4.8	3.6	7.9	3.7	7.4	7.5	3.7	4.5	6.9	2.9	6.6	4.0	9.3	5.4	12
13	Residential	13.0	12.4	3.8	10.2	6.5	3.5	-1.5	-1.5	15.4	7.1	7.7	9.1	3.9	4.2	-4.4	1.7	13
14	Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	14
15	**Net exports of goods and services**	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	15
16	Exports	3.4	3.6	4.2	0.5	0.0	3.5	3.0	0.0	2.1	6.0	2.9	-1.5	1.1	5.5	0.4	0.3	16
17	Goods	3.8	3.2	4.6	-0.4	0.6	3.9	4.3	0.2	1.4	7.1	2.8	-3.1	2.5	5.9	1.4	0.0	17
18	Services	2.4	4.5	3.3	2.2	-1.1	2.7	0.7	-0.4	3.8	3.7	3.2	1.6	-1.6	4.8	-1.6	0.9	18
19	Imports	2.7	1.5	5.0	5.3	2.0	4.7	4.4	1.0	0.6	3.0	6.5	3.2	3.4	5.6	3.2	-2.1	19
20	Goods	2.6	1.8	5.6	5.7	1.5	4.8	5.0	0.3	0.5	3.4	7.1	3.2	3.1	6.0	3.4	-3.4	20
21	Services	3.1	0.5	2.3	3.5	4.4	4.4	1.6	4.2	1.4	1.1	3.5	3.3	4.8	3.8	2.4	3.3	21
22	**Government consumption expenditures and gross investment**	**-2.1**	**-2.4**	**-0.9**	**1.9**	**1.8**	**0.7**	**1.7**	**2.3**	**-2.1**	**-2.4**	**0.3**	**2.3**	**1.5**	**0.8**	**1.5**	**3.0**	22
23	Federal	-1.9	-5.5	-2.6	-0.1	0.4	0.8	2.9	3.5	-2.6	-6.1	-1.1	1.1	0.1	1.7	2.7	4.3	23
24	National defense	-3.4	-6.7	-4.1	-2.1	-0.6	0.7	3.3	4.9	-4.7	-6.5	-3.4	-0.4	-0.8	1.9	4.0	4.4	24
25	Nondefense	0.9	-3.5	-0.1	3.1	2.0	0.8	2.4	1.6	1.2	-5.5	2.7	3.4	1.5	1.4	0.7	4.1	25
26	State and local	-2.2	-0.3	0.2	3.2	2.6	0.6	1.0	1.6	-1.7	0.2	1.2	3.0	2.3	0.4	0.9	2.2	26
	Addenda:																	
27	Gross domestic income (GDI) [1]	3.4	1.3	3.2	2.7	0.8	2.1	2.5	1.9	2.9	1.5	4.2	1.3	0.9	2.5	2.3	2.0	27
28	Average of GDP and GDI	2.8	1.6	2.9	2.8	1.2	2.2	2.7	2.1	2.2	2.1	3.5	1.6	1.5	2.6	2.4	2.2	28
29	Final sales of domestic product	2.1	1.6	2.7	2.6	2.2	2.3	2.8	2.2	1.9	2.0	3.2	1.8	2.2	2.9	2.2	2.7	29
30	Gross domestic purchases	2.2	1.6	2.7	3.6	1.9	2.6	3.1	2.4	1.2	2.2	3.4	2.5	2.3	2.9	2.9	1.9	30
31	Final sales to domestic purchasers	2.0	1.3	2.8	3.3	2.4	2.5	3.0	2.3	1.7	1.7	3.7	2.5	2.6	2.9	2.6	2.3	31
32	Final sales to private domestic purchasers	3.0	2.2	3.7	3.6	2.6	2.9	3.3	2.3	2.6	2.6	4.5	2.5	2.8	3.4	2.8	2.1	32
33	Gross national product	2.2	1.8	2.5	2.8	1.6	2.5	3.0	2.4	1.2	2.6	2.8	1.9	2.1	2.8	2.4	2.6	33
34	Real disposable personal income	3.3	-1.3	4.1	4.1	1.8	2.9	4.0	2.9	4.9	-2.5	5.3	3.0	1.6	3.4	3.9	2.4	34
	Price indexes:																	
35	Gross domestic purchases	1.8	1.5	1.6	0.3	0.7	1.9	2.4	1.5	1.8	1.5	1.3	0.1	1.3	2.0	2.2	1.4	35
36	Gross domestic purchases excluding food and energy [2]	1.8	1.6	1.7	1.0	1.1	1.8	2.3	1.7	1.8	1.7	1.5	0.8	1.4	1.9	2.3	1.6	36
37	GDP	1.9	1.8	1.8	1.0	1.0	1.9	2.4	1.8	2.1	1.8	1.5	0.9	1.5	2.0	2.3	1.6	37
38	GDP excluding food and energy [2]	1.9	1.9	1.9	1.2	1.3	1.9	2.5	1.9	2.0	2.1	1.6	1.0	1.7	2.0	2.5	1.7	38
39	PCE	1.9	1.3	1.5	0.2	1.0	1.8	2.1	1.4	1.8	1.2	1.1	0.3	1.5	1.8	1.9	1.4	39
40	PCE excluding food and energy [2]	1.9	1.5	1.6	1.2	1.6	1.6	1.9	1.6	1.8	1.6	1.5	1.2	1.8	1.7	1.9	1.6	40
41	Market-based PCE [3]	1.8	1.0	1.1	-0.1	0.7	1.5	1.8	1.3	1.5	0.8	0.7	0.0	1.2	1.5	1.7	1.3	41
42	Market-based PCE excluding food and energy [2,3]	1.8	1.2	1.1	1.0	1.3	1.3	1.6	1.6	1.5	1.1	1.1	1.1	1.4	1.2	1.7	1.5	42

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

2. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

3. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Note. Estimates under the *Percent change from the preceding year* columns are calculated from annual data. Estimates under the *Percent change fourth quarter to fourth quarter* columns are calculated from fourth quarter values relative to the same quarter one year prior.

Source: U.S. Bureau of Economic Analysis

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Table 6. Real Gross Domestic Product: Percent Change From Quarter One Year Ago

Line		2016			2017				2018				2019				2020	Line
		Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
1	**Gross domestic product (GDP)**	**1.3**	**1.6**	**2.0**	**2.1**	**2.2**	**2.4**	**2.8**	**2.9**	**3.2**	**3.1**	**2.5**	**2.7**	**2.3**	**2.1**	**2.3**	**0.3**	1
2	**Personal consumption expenditures (PCE)**	**2.7**	**2.6**	**2.8**	**2.6**	**2.5**	**2.4**	**2.9**	**2.8**	**3.2**	**3.4**	**2.6**	**2.5**	**2.6**	**2.6**	**2.7**	**0.4**	2
3	Goods	3.7	3.5	3.6	3.4	3.6	3.7	5.0	4.5	4.5	4.4	2.9	3.0	3.8	4.2	3.9	3.2	3
4	Durable goods	5.1	6.4	7.3	6.7	6.9	6.2	7.7	7.4	7.5	6.4	3.8	3.2	4.4	5.5	5.9	1.3	4
5	Nondurable goods	3.0	2.1	1.8	1.7	2.0	2.4	3.7	3.1	3.0	3.4	2.5	2.9	3.5	3.5	3.0	4.1	5
6	Services	2.3	2.2	2.4	2.2	1.9	1.9	2.0	2.0	2.6	3.0	2.5	2.3	2.1	1.8	2.1	-0.9	6
7	**Gross private domestic investment**	**-2.5**	**-2.2**	**1.5**	**2.8**	**4.2**	**5.9**	**4.8**	**5.5**	**4.1**	**5.5**	**5.1**	**5.1**	**3.9**	**0.4**	**-1.9**	**-4.8**	7
8	Fixed investment	1.6	1.7	2.8	4.0	4.1	3.5	5.1	4.6	5.2	5.0	3.5	2.9	1.3	0.9	0.1	-1.3	8
9	Nonresidential	0.0	1.1	2.4	4.2	4.3	3.5	5.4	6.0	6.9	6.8	5.9	4.8	2.6	1.4	-0.4	-3.6	9
10	Structures	-9.7	-2.1	4.3	9.4	7.3	0.9	1.5	2.6	4.8	6.4	2.6	0.7	-4.8	-6.7	-6.2	-9.5	10
11	Equipment	-0.9	-2.7	-1.4	1.1	3.9	5.4	8.5	8.6	7.2	6.4	5.0	3.3	2.7	1.0	-1.8	-5.8	11
12	Intellectual property products	9.1	9.2	6.6	5.0	2.8	2.8	4.0	4.8	7.8	7.5	9.3	9.6	7.5	7.7	5.4	2.9	12
13	Residential	7.5	4.0	3.9	3.3	3.2	3.3	4.2	-0.1	-0.4	-0.9	-4.4	-3.4	-3.2	-1.1	1.7	7.0	13
14	Change in private inventories	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	14
15	**Net exports of goods and services**	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	15
16	Exports	-1.2	1.3	1.1	3.3	2.7	2.3	5.5	4.1	5.2	2.4	0.4	1.2	-1.7	0.2	0.3	-2.9	16
17	Goods	-1.3	1.6	2.5	3.7	3.6	2.3	5.9	4.7	7.1	4.0	1.4	2.2	-2.1	0.8	0.0	-1.4	17
18	Services	-0.9	0.7	-1.6	2.6	1.2	2.3	4.8	3.2	1.7	-0.5	-1.6	-0.7	-0.7	-1.0	0.9	-5.8	18
19	Imports	1.2	1.6	3.4	4.2	4.9	4.1	5.6	4.7	3.9	5.7	3.2	2.6	2.6	0.9	-2.1	-5.8	19
20	Goods	0.6	0.9	3.1	4.2	4.8	4.1	6.0	5.3	4.7	6.7	3.4	2.3	2.1	0.1	-3.4	-5.6	20
21	Services	3.9	4.4	4.8	4.4	5.5	4.0	3.8	2.1	0.6	1.4	2.4	4.3	4.7	4.3	3.3	-6.5	21
22	**Government consumption expenditures and gross investment**	**1.6**	**1.5**	**1.5**	**0.5**	**1.0**	**0.5**	**0.8**	**1.4**	**1.7**	**2.2**	**1.5**	**1.8**	**2.3**	**2.2**	**3.0**	**2.4**	22
23	Federal	0.1	0.6	0.1	-0.4	1.1	0.7	1.7	2.7	2.8	3.6	2.7	2.5	3.6	3.7	4.3	4.1	23
24	National defense	-1.6	0.1	-0.8	-1.2	1.8	0.5	1.9	2.5	2.7	3.9	4.0	5.8	4.8	4.6	4.4	2.7	24
25	Nondefense	2.5	1.3	1.5	0.9	0.2	0.9	1.4	2.9	3.0	3.1	0.7	-2.1	1.9	2.4	4.1	6.4	25
26	State and local	2.5	2.0	2.3	0.9	0.9	0.4	0.4	0.6	1.0	1.5	0.9	1.3	1.6	1.4	2.2	1.4	26
	Addenda:																	
27	Gross domestic income (GDI) [1]	0.5	0.8	0.9	1.3	2.5	2.2	2.5	2.7	2.2	2.8	2.3	2.0	2.0	1.5	2.0	.....	27
28	Average of GDP and GDI	0.9	1.2	1.5	1.7	2.3	2.3	2.6	2.8	2.7	3.0	2.4	2.3	2.2	1.8	2.2	.....	28
29	Final sales of domestic product	2.1	2.2	2.2	2.3	2.1	2.0	2.9	2.7	3.4	3.0	2.2	2.3	1.8	2.2	2.7	0.9	29
30	Gross domestic purchases	1.6	1.6	2.3	2.3	2.5	2.7	2.9	3.0	3.1	3.6	2.9	2.8	2.8	2.1	1.9	-0.2	30
31	Final sales to domestic purchasers	2.3	2.3	2.6	2.5	2.5	2.3	2.9	2.8	3.2	3.5	2.6	2.5	2.4	2.2	2.3	0.4	31
32	Final sales to private domestic purchasers	2.5	2.4	2.8	2.9	2.8	2.6	3.4	3.1	3.6	3.8	2.8	2.6	2.4	2.2	2.1	0.0	32
33	Gross national product	1.3	1.5	2.1	2.2	2.1	2.7	2.8	3.1	3.4	3.2	2.4	2.5	2.4	2.2	2.6	.....	33
34	Real disposable personal income	1.6	1.3	1.6	2.2	2.9	3.1	3.4	3.9	3.9	4.1	3.9	3.3	3.0	2.7	2.4	1.4	34
	Price indexes:																	
35	Gross domestic purchases	0.5	0.7	1.3	2.0	1.7	1.8	2.0	2.2	2.5	2.5	2.2	1.7	1.6	1.5	1.4	1.7	35
36	Gross domestic purchases excluding food and energy [2]	0.9	1.1	1.4	1.8	1.7	1.8	1.9	2.1	2.4	2.4	2.3	1.9	1.7	1.7	1.6	1.7	36
37	GDP	0.9	0.9	1.5	2.0	1.7	1.9	2.0	2.1	2.6	2.5	2.3	2.0	1.8	1.7	1.6	1.7	37
38	GDP excluding food and energy [2]	1.2	1.3	1.7	2.1	1.8	1.9	2.0	2.2	2.6	2.6	2.5	2.1	2.0	1.9	1.7	1.9	38
39	PCE	0.8	1.0	1.5	2.0	1.6	1.6	1.8	1.9	2.3	2.2	1.9	1.4	1.4	1.4	1.4	1.6	39
40	PCE excluding food and energy [2]	1.5	1.7	1.8	1.8	1.6	1.5	1.7	1.8	2.0	2.0	1.9	1.6	1.6	1.7	1.6	1.8	40
41	Market-based PCE [3]	0.5	0.6	1.2	1.8	1.3	1.3	1.5	1.5	2.0	2.0	1.7	1.3	1.3	1.3	1.3	1.4	41
42	Market-based PCE excluding food and energy [2,3]	1.3	1.4	1.4	1.5	1.2	1.1	1.2	1.3	1.7	1.7	1.7	1.6	1.5	1.6	1.5	1.5	42

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

2. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

3. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Source: U.S. Bureau of Economic Analysis

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Table 7. Relation of Gross Domestic Product, Gross National Product, and National Income

[Billions of dollars]

Line		2017	2018	2019	Seasonally adjusted at annual rates					Line
					2019				2020	
					Q1	Q2	Q3	Q4	Q1	
1	**Gross domestic product (GDP)**	**19,519.4**	**20,580.2**	**21,427.7**	**21,098.8**	**21,340.3**	**21,542.5**	**21,729.1**	**21,537.9**	1
2	Plus: Income receipts from the rest of the world	957.9	1,106.2	1,158.8	1,149.0	1,177.2	1,160.4	1,148.7	.....	2
3	Less: Income payments to the rest of the world	714.6	838.3	863.3	891.2	876.2	851.4	834.5	.....	3
4	**Equals: Gross national product**	**19,762.7**	**20,848.1**	**21,723.2**	**21,356.7**	**21,641.3**	**21,851.5**	**22,043.4**	**.....**	4
5	Less: Consumption of fixed capital	3,121.4	3,291.4	3,463.0	3,402.2	3,446.5	3,485.9	3,517.3	3,551.7	5
6	Less: Statistical discrepancy	-67.6	10.8	105.1	42.1	102.5	149.5	126.2	.....	6
7	**Equals: National income**	**16,708.8**	**17,545.9**	**18,155.2**	**17,912.4**	**18,092.3**	**18,216.2**	**18,399.8**	**.....**	7
8	Compensation of employees	10,411.6	10,928.5	11,420.9	11,306.6	11,386.9	11,441.7	11,548.2	11,559.2	8
9	Wages and salaries	8,462.1	8,888.5	9,297.8	9,211.5	9,273.6	9,309.6	9,396.3	9,398.3	9
10	Supplements to wages and salaries	1,949.5	2,040.0	2,123.1	2,095.1	2,113.3	2,132.1	2,151.9	2,160.9	10
11	Proprietors' income with inventory valuation and capital consumption adjustments	1,518.2	1,588.8	1,658.2	1,621.2	1,632.9	1,683.4	1,695.6	1,698.5	11
12	Rental income of persons with capital consumption adjustment	718.8	756.8	777.9	767.0	777.2	779.7	787.7	797.8	12
13	Corporate profits with inventory valuation and capital consumption adjustments	2,005.9	2,074.6	2,074.6	2,006.9	2,082.7	2,078.0	2,131.0	.....	13
14	Net interest and miscellaneous payments	608.0	672.6	644.9	657.2	644.7	636.4	641.5	640.6	14
15	Taxes on production and imports less subsidies	1,303.3	1,377.4	1,420.1	1,399.8	1,417.4	1,425.1	1,438.0	1,460.8	15
16	Business current transfer payments (net)	145.4	153.7	170.7	165.4	163.3	184.6	169.6	175.7	16
17	Current surplus of government enterprises	-2.5	-6.5	-12.2	-11.5	-12.9	-12.6	-11.7	-18.6	17
	Addenda:									
18	Gross domestic income (GDI)	19,587.0	20,569.4	21,322.6	21,056.7	21,237.8	21,393.1	21,602.9	.....	18
19	Average of GDP and GDI	19,553.2	20,574.8	21,375.2	21,077.8	21,289.0	21,467.8	21,666.0	.....	19
20	Statistical discrepancy as a percentage of GDP	-0.3	0.1	0.5	0.2	0.5	0.7	0.6	.....	20

Source: U.S. Bureau of Economic Analysis

April 29, 2020

Table 8. Personal Income and Its Disposition

[Billions of dollars]

Line		2017	2018	2019	Seasonally adjusted at annual rates					Line
					2019				2020	
					Q1	Q2	Q3	Q4	Q1	
1	**Personal income** [1]	**16,878.8**	**17,819.2**	**18,602.3**	**18,355.4**	**18,555.9**	**18,676.9**	**18,821.0**	**18,916.2**	1
2	Compensation of employees	10,411.6	10,928.5	11,420.9	11,306.6	11,386.9	11,441.7	11,548.2	11,559.2	2
3	Wages and salaries	8,462.1	8,888.5	9,297.8	9,211.5	9,273.6	9,309.6	9,396.3	9,398.3	3
4	Supplements to wages and salaries	1,949.5	2,040.0	2,123.1	2,095.1	2,113.3	2,132.1	2,151.9	2,160.9	4
5	Proprietors' income with inventory valuation and capital consumption adjustments	1,518.2	1,588.8	1,658.2	1,621.2	1,632.9	1,683.4	1,695.6	1,698.5	5
6	Farm	38.1	27.2	32.0	24.8	19.2	41.8	42.1	37.3	6
7	Nonfarm	1,480.1	1,561.6	1,626.3	1,596.3	1,613.7	1,641.5	1,653.5	1,661.2	7
8	Rental income of persons with capital consumption adjustment	718.8	756.8	777.9	767.0	777.2	779.7	787.7	797.8	8
9	Personal income receipts on assets	2,681.6	2,930.1	2,992.9	2,955.1	3,016.5	2,997.7	3,002.2	3,017.5	9
10	Personal interest income	1,551.6	1,702.7	1,720.6	1,699.3	1,750.5	1,716.8	1,715.6	1,711.7	10
11	Personal dividend income	1,130.0	1,227.5	1,272.3	1,255.8	1,266.0	1,280.9	1,286.6	1,305.9	11
12	Personal current transfer receipts	2,848.1	2,971.5	3,171.9	3,113.1	3,158.6	3,195.8	3,220.3	3,287.9	12
13	Less: Contributions for government social insurance, domestic	1,299.6	1,356.5	1,419.5	1,407.6	1,416.3	1,421.3	1,432.9	1,444.8	13
14	Less: Personal current taxes	2,045.8	2,077.6	2,182.0	2,156.9	2,200.1	2,175.3	2,195.7	2,214.2	14
15	**Equals: Disposable personal income**	**14,833.0**	**15,741.5**	**16,420.3**	**16,198.5**	**16,355.7**	**16,501.6**	**16,625.3**	**16,702.0**	15
16	Less: Personal outlays	13,802.1	14,531.1	15,122.3	14,823.0	15,073.1	15,237.2	15,356.0	15,102.5	16
17	**Equals: Personal saving**	**1,030.9**	**1,210.4**	**1,297.9**	**1,375.5**	**1,282.6**	**1,264.3**	**1,269.3**	**1,599.5**	17
18	Personal saving as a percentage of disposable personal income	7.0	7.7	7.9	8.5	7.8	7.7	7.6	9.6	18
	Addenda:									
19	Personal income excluding current transfer receipts, billions of chained (2012) dollars [2]	13,245.3	13,729.6	14,071.4	13,999.8	14,059.1	14,083.6	14,144.3	14,122.1	19
20	Disposable personal income, billions of chained (2012) dollars [2]	14,002.8	14,556.2	14,974.1	14,878.1	14,934.3	15,011.9	15,073.2	15,092.3	20

1. Personal income is also equal to national income less corporate profits with inventory valuation and capital consumption adjustments, taxes on production and imports less subsidies, contributions for government social insurance, net interest and miscellaneous payments, business current transfer payments (net), and current surplus of government enterprises, plus personal income receipts on assets, and personal current transfer receipts.

2. The current-dollar measure is deflated by the implicit price deflator for personal consumption expenditures.

Source: U.S. Bureau of Economic Analysis

April 29, 2020

Appendix Table A. Real Gross Domestic Product and Related Aggregates: Percent Change From Preceding Period and Contributions to Percent Change

Line		2017	2018	2019	Seasonally adjusted at annual rates																Line
					2016			2017				2018				2019				2020	
					Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
	Percent change from preceding period																				
	Gross domestic product (GDP) and related aggregates:																				
1	GDP	2.4	2.9	2.3	1.9	2.2	2.0	2.3	2.2	3.2	3.5	2.5	3.5	2.9	1.1	3.1	2.0	2.1	2.1	-4.8	1
2	Goods	3.8	5.0	4.7	1.7	2.2	2.1	2.5	5.8	8.8	3.7	4.0	5.3	4.8	4.8	7.3	2.1	4.1	1.7	-1.9	2
3	Services	1.6	2.2	1.8	2.1	1.9	1.6	1.5	0.8	1.8	3.0	2.0	2.7	2.8	0.6	1.0	2.7	1.8	2.5	-7.6	3
4	Structures	3.0	0.8	-1.5	0.8	4.2	5.0	7.4	-0.4	-5.1	7.1	1.8	3.0	-2.5	-7.7	3.9	-3.1	-2.5	1.2	7.2	4
5	Motor vehicle output	-0.9	7.5	-0.2	4.0	3.9	-6.0	-6.2	1.7	-4.7	25.3	9.6	-0.3	10.3	1.3	-7.6	-7.6	34.7	-26.6	-18.7	5
6	GDP excluding motor vehicle output	2.5	2.8	2.4	1.8	2.1	2.3	2.5	2.2	3.4	3.0	2.4	3.6	2.7	1.1	3.4	2.3	1.3	3.1	-4.4	6
7	Nonfarm business gross value added [1]	2.9	3.5	2.7	2.0	2.4	2.7	2.5	2.7	4.2	4.2	2.9	4.0	3.5	1.2	3.9	1.9	2.3	2.4	-6.2	7
	Contributions to percent change in real gross domestic product																				
8	**Percent change at annual rate: Gross domestic product**	**2.4**	**2.9**	**2.3**	**1.9**	**2.2**	**2.0**	**2.3**	**2.2**	**3.2**	**3.5**	**2.5**	**3.5**	**2.9**	**1.1**	**3.1**	**2.0**	**2.1**	**2.1**	**-4.8**	8
	Percentage points at annual rates:																				
9	Goods	1.11	1.46	1.36	0.52	0.65	0.62	0.72	1.66	2.52	1.09	1.16	1.55	1.41	1.39	2.12	0.62	1.20	0.51	-0.51	9
10	Services	1.02	1.40	1.10	1.32	1.20	1.00	0.96	0.53	1.12	1.87	1.24	1.70	1.73	0.37	0.66	1.66	1.11	1.51	-4.85	10
11	Structures	0.25	0.07	-0.13	0.06	0.34	0.41	0.60	-0.03	-0.44	0.58	0.15	0.26	-0.21	-0.67	0.32	-0.26	-0.21	0.10	0.58	11
12	Motor vehicle output	-0.03	0.21	0.00	0.11	0.11	-0.18	-0.18	0.05	-0.13	0.63	0.26	-0.01	0.28	0.04	-0.22	-0.21	0.83	-0.85	-0.53	12

1. Consists of GDP less gross value added of farm, of households and institutions, and of general government.

Source: U.S. Bureau of Economic Analysis

Appendix Table B. Not Seasonally Adjusted Real Gross Domestic Product: Level and Percent Change From Quarter One Year Ago

Line		Billions of chained (2012) dollars at quarterly rates										Percent change from quarter one year ago									Line
		2017	2018				2019				2020	2018				2019				2020	
		Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	
1	**Gross domestic product (GDP)**	**4,678.3**	**4,491.4**	**4,651.1**	**4,707.3**	**4,788.4**	**4,611.1**	**4,760.0**	**4,795.9**	**4,893.5**	**4,633.1**	**3.5**	**3.0**	**2.9**	**2.4**	**2.7**	**2.3**	**1.9**	**2.2**	**0.5**	1
2	Personal consumption expenditures	3,280.4	3,106.0	3,231.6	3,240.8	3,366.1	3,178.6	3,319.6	3,334.5	3,464.0	3,201.7	3.0	3.1	3.3	2.6	2.3	2.7	2.9	2.9	0.7	2
3	Gross private domestic investment	814.9	786.6	828.0	892.8	853.2	832.8	857.6	883.4	822.2	794.1	8.1	3.3	4.5	4.7	5.9	3.6	-1.0	-3.6	-4.7	3
4	Net exports of goods and services	-222.9	-192.1	-224.3	-250.2	-253.4	-204.7	-256.3	-265.0	-232.1	-179.7	.....	.....	.....	.....	.....	.....	.....	.....	.....	4
5	Exports	636.0	625.1	638.9	631.6	637.4	628.4	627.3	630.8	639.5	614.3	4.8	5.0	2.3	0.2	0.5	-1.8	-0.1	0.3	-2.2	5
6	Imports	858.9	817.2	863.3	881.8	890.8	833.2	883.6	895.8	871.6	794.0	4.6	3.7	5.5	3.7	2.0	2.4	1.6	-2.2	-4.7	6
7	Government consumption expenditures and gross investment	799.9	787.1	808.8	814.4	813.6	800.8	829.2	831.9	835.8	819.3	1.3	1.5	2.3	1.7	1.7	2.5	2.2	2.7	2.3	7
	Addenda:																				
	Current dollar measures: (Billions of dollars)																				
8	GDP	5,065.1	4,917.1	5,141.7	5,210.0	5,311.4	5,148.4	5,360.9	5,404.7	5,517.6	5,261.5	5.8	5.7	5.4	4.9	4.7	4.3	3.7	3.9	2.2	8
9	Gross domestic income	5,035.3	5,113.8	5,057.2	5,101.8	5,296.6	5,303.4	5,246.5	5,270.9	5,511.2	.....	4.8	4.7	5.4	5.2	3.7	3.7	3.3	4.1	.....	9

Source: U.S. Bureau of Economic Analysis

S&P Global
Ratings

RatingsDirect®

COVID-19: The Outlook For North American Regulated Utilities Turns Negative

April 2, 2020

Key Takeaways

- We are revising our assessment of the North America regulated utility industry to negative from stable.
- We expect that the utility industry will remain a high-credit-quality investment-grade industry.
- We expect that the industry's median rating, which is 'A-', could weaken to the 'BBB+' level.
- Prior to the coronavirus outbreak in North America about 25% of the utilities had a negative outlook or ratings that were on CreditWatch with negative implications.
- Additionally, many utilities with a stable outlook have minimal financial cushion at the current rating level.
- We expect COVID-19 will weaken the industry's 2020 funds from operations (FFO) to debt by about 100 basis points.

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S&P Global Ratings acknowledges a high degree of uncertainty about the rate of spread and peak of the coronavirus outbreak. Some government authorities estimate the pandemic will peak about midyear, and we are using this assumption in assessing the economic and credit implications. We believe the measures adopted to contain COVID-19 have pushed the global economy into recession (see our macroeconomic and credit updates here: www.spglobal.com/ratings). As the situation evolves, we will update our assumptions and estimates accordingly.

S&P Global Ratings is revising downward its assessment of the North America utility industry to negative from stable. The North America utility industry consists of about 250 water, gas, and electric utilities. While we expect the sector to remain an investment-grade industry, we nevertheless project a modest weakening of credit quality within the industry. Credit quality had been gradually weakening prior to the COVID-19 outbreak with about 25% of companies on negative outlook or with ratings on CreditWatch with negative implications. We view COVID-19 as a source of incremental pressure and expect that the recession will lead to an increasing number of downgrades and negative outlooks. Currently, the median rating within the industry is 'A-' and over the next 12 months, we expect that the industry median could move to 'BBB+'.

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Credit Quality Was Weakening Even Before COVID-19

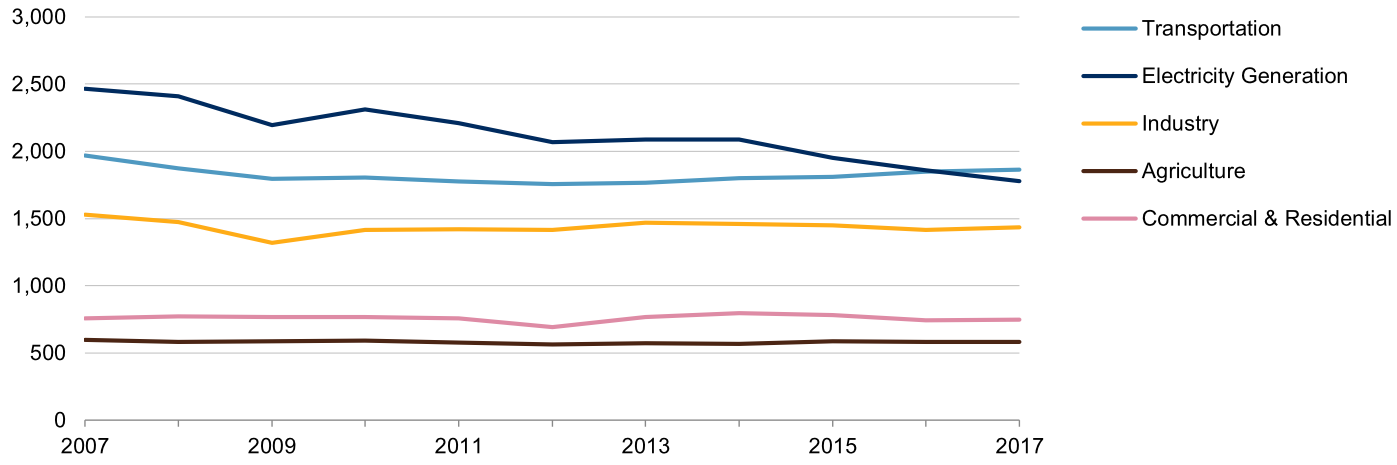
The North America regulated utility industry's credit quality was already weakening prior to COVID-19. This reflected companies' more consistent ability to manage credit measures closer to the downgrade threshold, leaving very minimal financial cushion at the current rating level. We generally view the industry's cash flows as more predictable and steady than most other corporate industries. Even so, unless a management team can proactively implement corrective actions, a utility with minimal financial cushion at the current rating coupled with an unexpected material event, typically results in a negative outlook or a downgrade.

The industry has faced many unexpected events and credit obstacles over the past two years. Some of these include safety (NiSource Inc.), wildfires (PG&E Corp., Edison International, and Sempra Energy), large capital projects (Southern Co., SCANA Corp., Eversource Energy, Duke Energy Corp., and Dominion Energy Inc.), utility acquisition (Fortis Inc., Emera Inc., ENMAX Corp., and NextEra Energy Inc.), and nonutility acquisitions (DTE Energy Co.). Each of these instances have either significantly reduced the prior cushion at the current rating level, triggered negative outlooks, or downgrades.

Also pressuring the industry's credit quality is the critical focus on environmental, social, and governance (ESG) factors. Over the past decade, the industry has done an outstanding job to significantly reduce its greenhouse gas emissions and reduce its reliance on coal-fired generation.

Chart 1

Total U.S. Greenhouse Gas Emissions By Economic Sector From 2007-2017
Million metric tons of CO2 equivalents



Source: U.S. Energy Information Administration.

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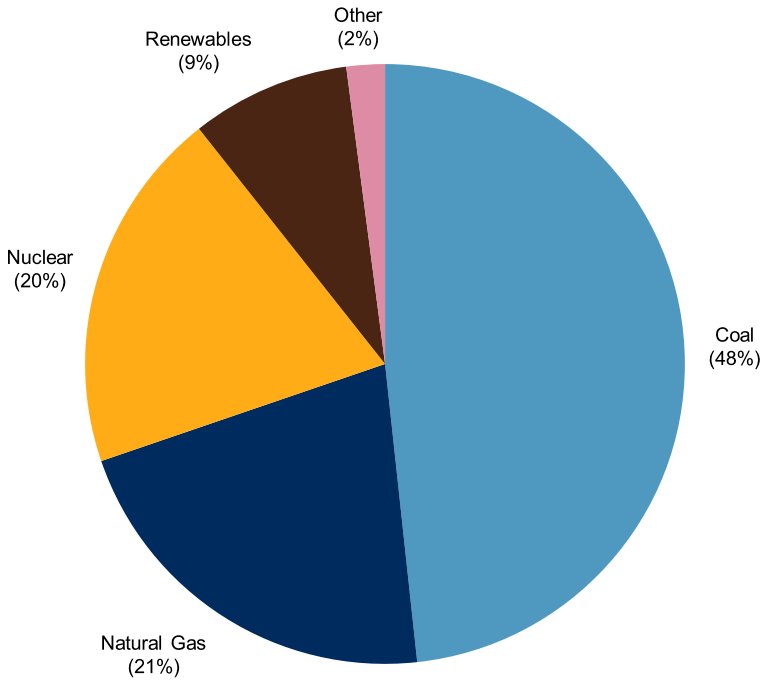
Chart 2

U.S. 2008 Generation Mix



Source: U.S. Energy Information Administration.

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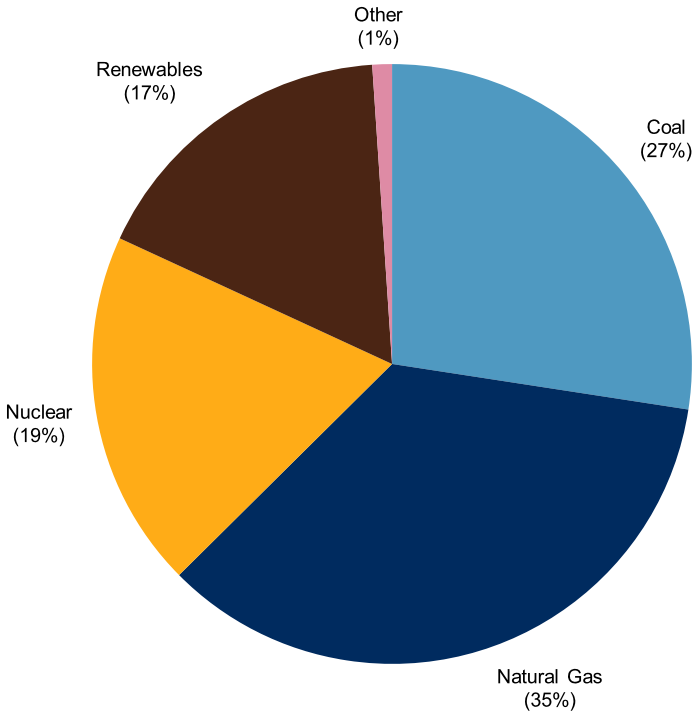
Chart 3

U.S. 2018 Generation Mix



Source: U.S. Energy Information Administration.

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However, there are individual companies such as American Electric Power Co. Inc., Ameren Corp., and Evergy Inc. that despite having long-term plans to reduce their reliance on coal-fired generation, will continue to rely heavily on that fuel source for the next decade, possibly pressuring credit quality.

Rating Upgrades And Downgrades

Over the past decade, there have been generally more upgrades than downgrades in the sector. This has strengthened the utilities' credit quality since the financial recession and currently, the median rating within the industry is 'A-'.

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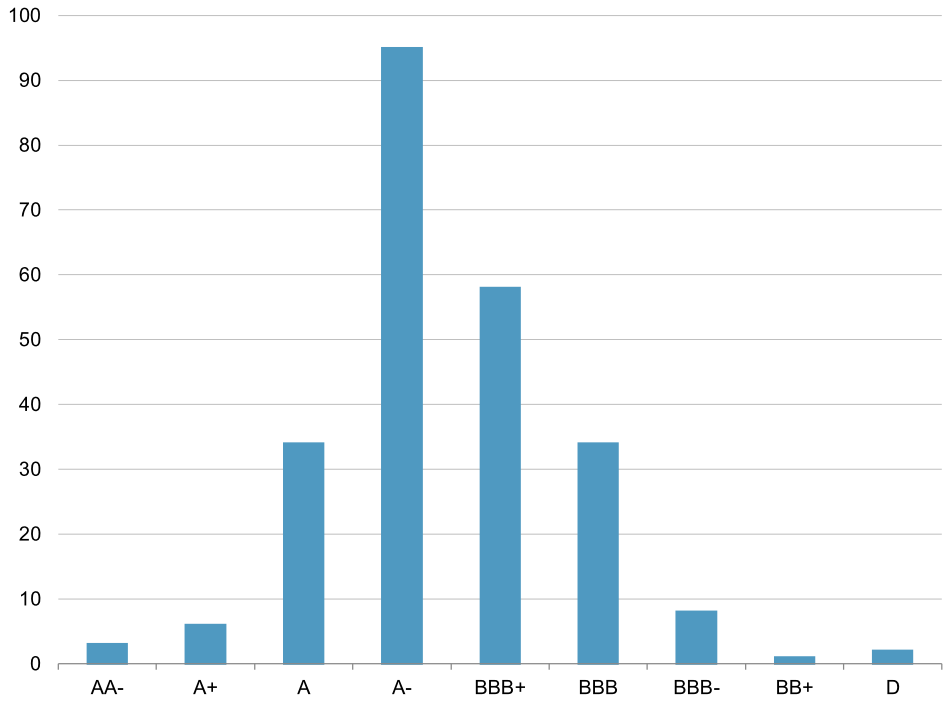
Chart 4

North American Regulated Utilities Ratings Distribution 2019



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When analyzing our rating upgrades and downgrades in the sector for 2019, even prior to COVID-19, we note a weakening of credit quality.

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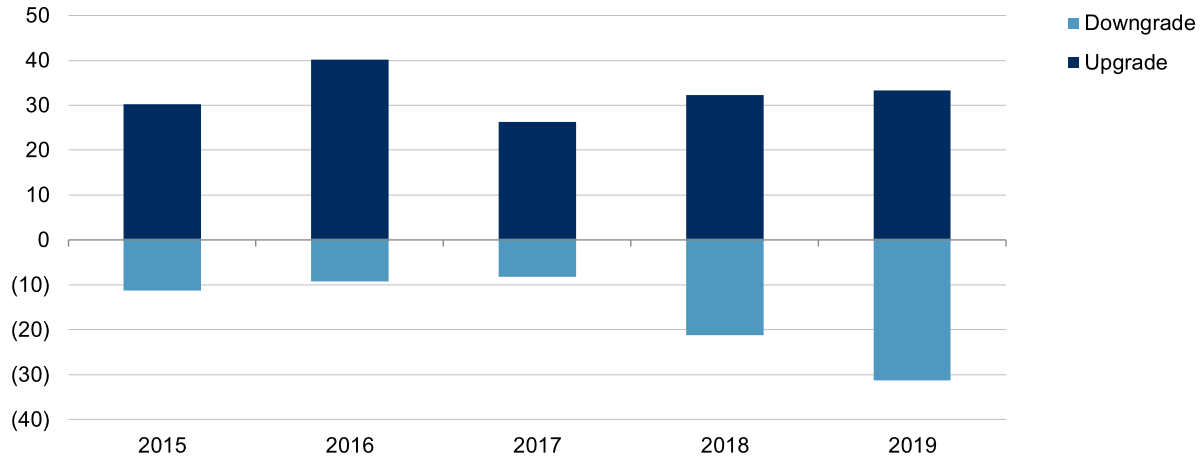
Chart 5

North American Regulated Utilities Upgrades And Downgrades



Source: S&P Global Ratings.

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While 2019 may initially appear to be similar to prior years with upgrades outpacing downgrades at 33 to 31, the underlying analysis tells a different story. In 2019, about 60% of the upgrades were attributed to S&P Global Ratings' revised group rating methodology criteria. Under the revised criteria, we placed more emphasis on the regulation of a utility allowing for a subsidiary with effective regulation and with a stand-alone credit profile that is higher than its group to potentially be rated higher. Absent the revised criteria, downgrades would have outpaced upgrades by 30 to 13 in 2019. This is a clear indication that even before COVID-19, the credit quality of the North America regulated utility sector had weakened.

Operating With Minimal Financial Cushion

While many companies with a negative outlook such as Puget Energy Inc. have minimal financial cushion at their current rating level, many others with a stable outlook also have minimal financial cushion at their current rating level. Companies with a stable outlook and minimal financial cushion include Exelon Corp., ALLETE Inc., American Water Works Co. Inc., Edison International, AVANGRID Inc., DPL Inc., CenterPoint Energy Inc., and Madison Gas & Electric Co. As the financial effects of COVID-19 continue to take hold, we expect that even companies with stable outlooks may experience ratings downward pressure. This is another reason that underscores our assessment that the industry outlook has turned negative.

How COVID-19 May Affect The Sector

In general, we assume that the U.S. will experience more than a 12% contraction in GDP during the second quarter and estimate the pandemic will peak between June and August (Global Macroeconomic Update, March 24: A Massive Hit To World Economic Growth, March 24, 2020).

For the North America utility industry, we expect that COVID-19 will reduce the commercial and

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industrial (C&I) usage (North American Regulated Utilities Face Additional Risks Amid Coronavirus Outbreak, March 19, 2020). While some utilities will be able to offset some of the lower C&I usage through various regulatory mechanisms that include decoupling of revenues mechanisms and formula rates, many others will see a weakening of sales. Furthermore, as the recession continues to take hold, we expect bad debt expense will increase as it becomes increasingly more difficult for customers to pay their bills. While many utilities can defer these costs for future recovery, as these balances grow, historically we have seen incidents where utilities negotiate with their commission's to write off some of these costs as part of a larger agreement. Overall, we expect that these effects will result in a weakening of credit measures.

On a positive note, the industry continues to exhibit adequate liquidity and access to the debt markets, despite uneven performance of the commercial paper market for tier 2 issuers. The industry is benefiting from proactive risk management of establishing large credit facilities, having good access to additional liquidity through new term loans from banks, and public issuance of utility debt. These positive developments contrast to the last financial recession, when many utilities fully drew on their available credit lines and access to the banks or to the public debt market was effectively shut for many weeks.

Yet availability to the equity markets remains extraordinarily challenging. In 2019, the industry issued more than $30 billion in equity to preserve credit quality and heading into 2020 many companies within the industry assumed equity issuances as part of their financing plans. Given the industry's negative discretionary cash flow because of its high capital spending and lack of access to the equity markets, we expect that this will also lead to a weakening of credit measures.

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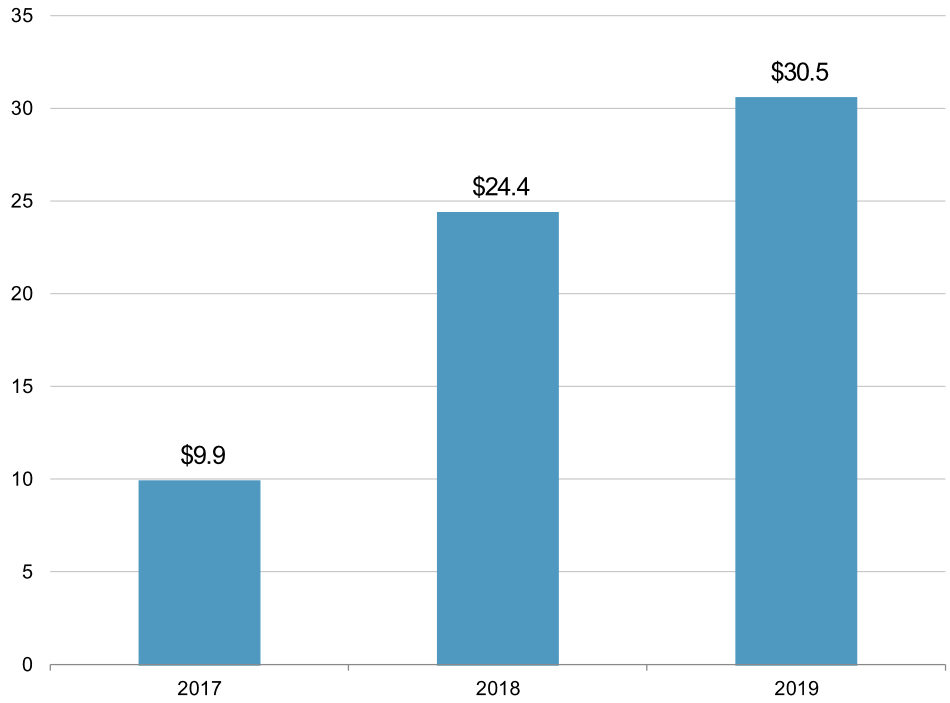
Chart 6

North American Regulated Utilities Equity Issuance In Billions



Source: S&P Global Ratings.
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Another area of concern are utilities that rely to various degrees on nonutility businesses that have commodity exposure (S&P Global Ratings Cuts WTI And Brent Crude Oil Price Assumptions Amid Continued Near-Term Pressure, March 19, 2020). These include OGE Energy Corp., CenterPoint Energy Inc., DTE Energy Co., Dominion Energy Inc., Public Service Enterprise Group Inc., NextEra Energy Inc., and Exelon Corp. While many of them are well hedged in the near term, volumetric risk and a longer-term weakening of commodity prices could have a material effect on their credit measures. Overall, assuming that the effects of COVID-19 is only temporary, we would expect that the industry's 2020 FFO to debt will weaken by about 100 basis points, consistent with our revised negative outlook for the industry.

The Industry Has Levers

Depending on the severity of the recession, the industry has important levers that could mitigate some of the risks. This includes reducing capital spending and dividends. Currently, we estimate that 2020 capital spending will approximate $150 billion.

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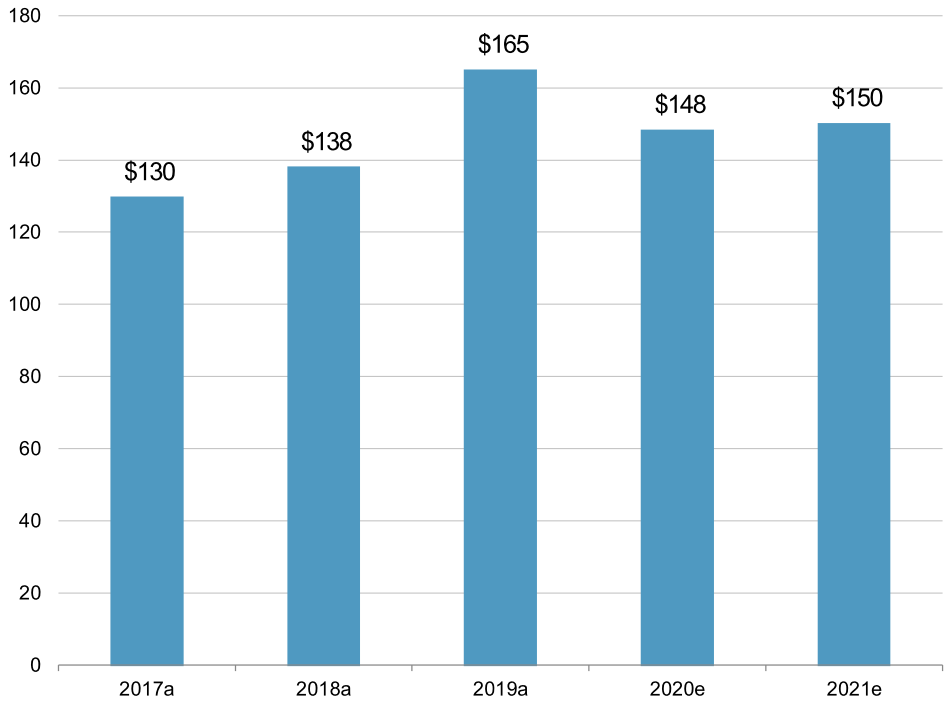
Chart 7

North American Regulated Utilities Capital Expenditures In Billions



a--actual. e--estimate. Source: S&P Global Ratings.

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Based on our conversations with the companies within the industry there is a wide range as to how deeply a utility can reduce its capital spending and still maintain safe and reliable services. Some utilities can only reduce capital spending by as little as 15%, others by as much as 60%. Our analysis indicates that the majority of utilities could reduce their capital spending on a temporary basis by about 40% and maintain safe operations. Should the recession prolong, we would expect that the industry would generally first reduce capital spending and only afterward cut dividends. There is precedent that during times of high financial stress, utilities have reduced their dividends and we would expect that the industry, if necessary, would use this lever, acting prudently to preserve credit quality.

Credit quality of the North America regulated utility industry was already weakening prior to COVID-19. We believe that incremental challenges that the industry will face from this recession exacerbates financial pressure and underpins our revised negative outlook for the industry. However, we also expect that this industry's credit quality will continue to outperform most other corporate industries despite these challenges. Furthermore, we expect that the utilities will use the levers available to them to reduce credit risks and limit the financial impact from COVID-19. Overall, while we expect a weakening to the industry's credit quality, we continue to firmly believe that this industry will remain a high-quality, investment-grade industry.

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6 May, 2020

S&P credits utilities' moves to bolster liquidity against virus impacts

Author **Ellie Potter**

Theme **Energy**

While the coronavirus pandemic has shaken industries all over the world, S&P Global Ratings expects the North American regulated utility sector to maintain its investment grade credit profile, helped by proactive measures the industry has taken to ensure liquidity through revolving credit facilities and issuing debt.

Many utilities entered into 364-day term loans during the first quarter to lock in liquidity at "reasonable rates," a move Ratings viewed positively. Doing so allowed the sector to "circumvent the volatile commercial paper markets, strengthening the industry's near-term liquidity position," S&P analysts wrote in a May 4 report.

"Despite the challenges associated with the economic downturn, the utility industry has preserved its investment-grade profile and maintaining adequate liquidity in part by securing multiyear revolving credit facilities

that are sized to sufficiently cover cash needs over a 12-month period," S&P Global Ratings said.

This response marks a contrast from the 2008 financial crisis when many utilities drew down credit facilities, weakening liquidity, S&P Global Ratings noted. Another positive contrast is the utility industry issuing a record amount of long-term debt in the first quarter, demonstrating healthy access to capital markets.

"Notably, holding companies, in addition to their utilities, were able to access the capital markets — another key difference compared to 2008," Ratings analysts wrote.

READ MORE: *Sign up for our weekly coronavirus newsletter* ***here****, and read our latest coverage on the crisis* ***here****.*

While the industry has performed well so far, the report cautioned that utilities' credit quality may weaken as companies with little financial cushion continue to weather the financial storm brought on by the COVID-19 outbreak. Ratings lowered its outlook for the sector from stable to negative in early April as a result.

But S&P Global Ratings expects capital spending by utilities to remain "robust," so long as access to capital markets remains, and the agency does not materially lower its economic outlook forecast.

Under the assumption that the virus will peak around mid-year, Ratings economists expect U.S. GDP to contract 5.2% in 2020 and headline unemployment to reach as high as 19% in May, according to the report. The credit rating agency said it took more than 680 rating actions and nearly 730 outlook revisions or CreditWatch placements globally over a six-week

period amid the outbreak and weakened oil market. The energy sector, followed by the banking industry, had the most affected issuers within the broader corporate ratings environment.

Utilities often operate with negative discretionary cash flow, so their "consistent access" to capital markets has proven critical to credit quality, according to the report.

"Importantly, should current economic conditions significantly weaken from S&P Global Ratings' base-case scenario or regular access to the debt markets subside, utilities would likely need to pull available levers to preserve liquidity and ultimately, credit quality," Ratings said. "This could include some form of reduction in capital spending, operating and maintenance costs, and dividends."

The sector has kept its essential services up and running, with many utilities requiring employees to use personal protective equipment and exercise social distancing for face-to-face interactions, according to the report. Companies have also allowed some staff to work remotely and enabled others to remain onsite at critical facilities throughout the pandemic.

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COMMENTARY

Correlations Going to 1: Amid Market Collapse, U.S. Stock Fund Factors Show Little Differentiation

We don't see connections between portfolio characteristics and returns when looking through the lens of our Factor Profile data.

David Carey, **Tom Lauricella**
Mar 6, 2020

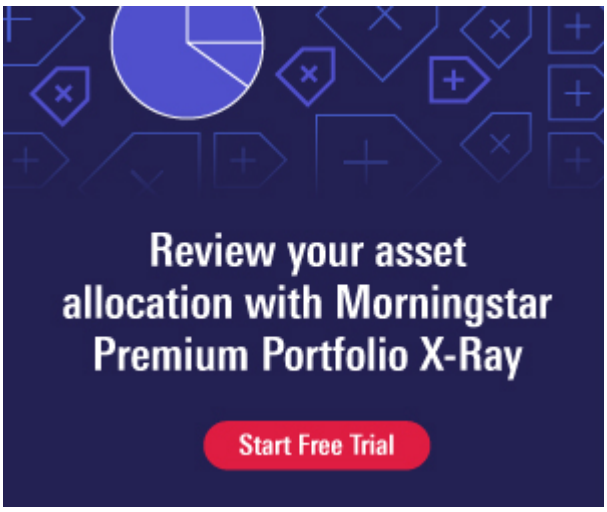
Editor's note: Read the latest *on how the coronavirus is rattling the markets and what investors can do to navigate it.*

There's an old saying in the financial markets that, during a time of crisis, "Correlations go to 1."

The meaning here is that when there's a panicked rush to the exits--as global stock markets have seen amid the spread of the coronavirus--all stocks are punished equally and indiscriminately. And fund investors have seen this sell first, ask questions later exodus in their portfolios.

While losses may just feel like losses, all market declines aren't alike. Often a market drop will see the asset classes or sectors that had done the best heading into the sell-off reverse course and post the largest declines. In that kind of environment, investments that had lagged tend to be more buoyant. In addition, in an orderly stock market retrenchment, defensive sectors such as higher-yielding stocks will also outperform.

But that hasn't been the case during the coronavirus market collapse.



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This sell-everything environment can be seen first through overall returns. On average, all nine categories of U.S. diversified stock funds lost between 10.8% and 11.6% starting from Feb. 19--when the S&P 500 hit a record high--and Feb. 27. That margin is a very narrow range for a chaotic market.

The run-for-the-hills mentality also became clear when we scouted for connections--or, in this case, a lack of connections--between portfolio characteristics and returns by looking at funds through the lens of Morningstar's Factor Profile data. This data set measures a fund's portfolio based on seven metrics: size, style, yield, momentum, quality, volatility, and liquidity.

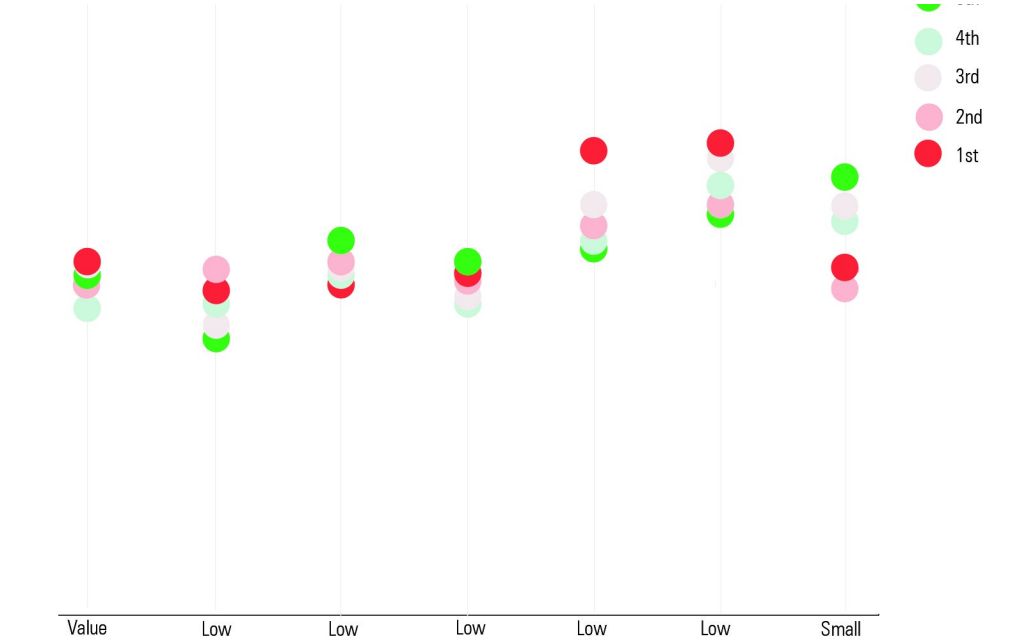
When we measure fund performance against these factors, we can see clear patterns of a "correlations go to 1" market. For this article, we focused on the universe of U.S. diversified-stock funds.

Between Feb. 19 and Feb. 27, whether funds tended to invest in growth or stocks, high yield or low yield, or strong or weak momentum, there was little overall differentiation. There was only a tiny bit more shelter to be found from the storm in funds focused on lower-volatility stocks.

U.S. Diversified Stock Fund Average Factor Exposures Broken Down by Return Quintiles, Feb. 19-27

Style	Yield	Momentum	Quality	Volatility	Liquidity	Size
Growth	High	High	High	High	High	Large

1-Week Return Quintile Rank
5th

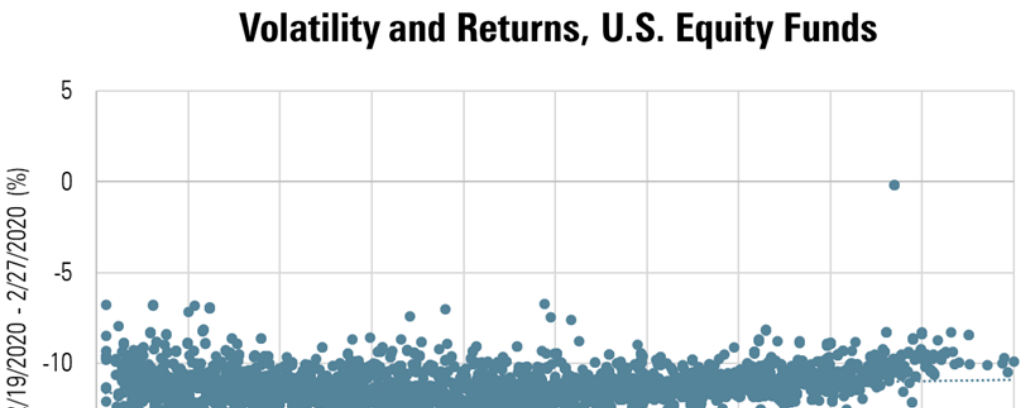


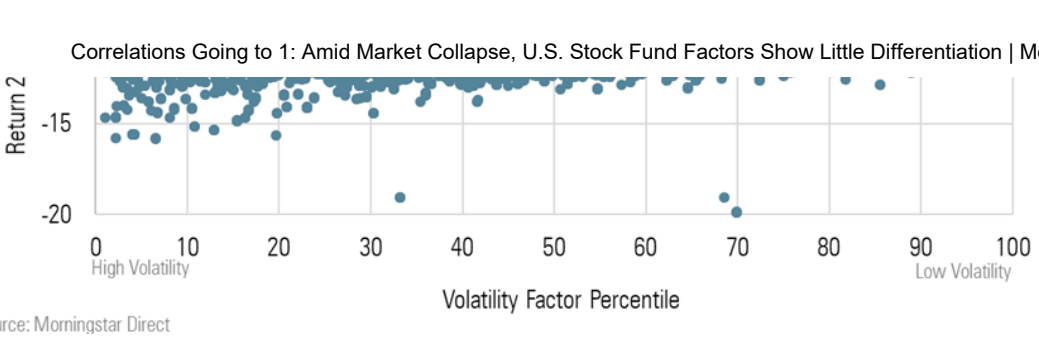
Source: Morningstar Direct, 1-Week Return is 2/19/2020 - 2/27/2020

As highlighted in our article "What's Driving U.S. Stock Fund Returns? ," during the three years ended Dec. 31, funds focused on the biggest, fastest-growing companies or stocks that were already on an uptrend performed better than funds that loaded up on smaller, undervalued companies or those without a clear uptrend or downtrend in place.

Volatility

Not too surprisingly, one of the characteristics that played out slightly better over the course of the recent sell-off were portfolios dominated by low-volatility stocks. Yet, the returns are still negative across the board regardless of high- or low-volatility exposure and the gap between.



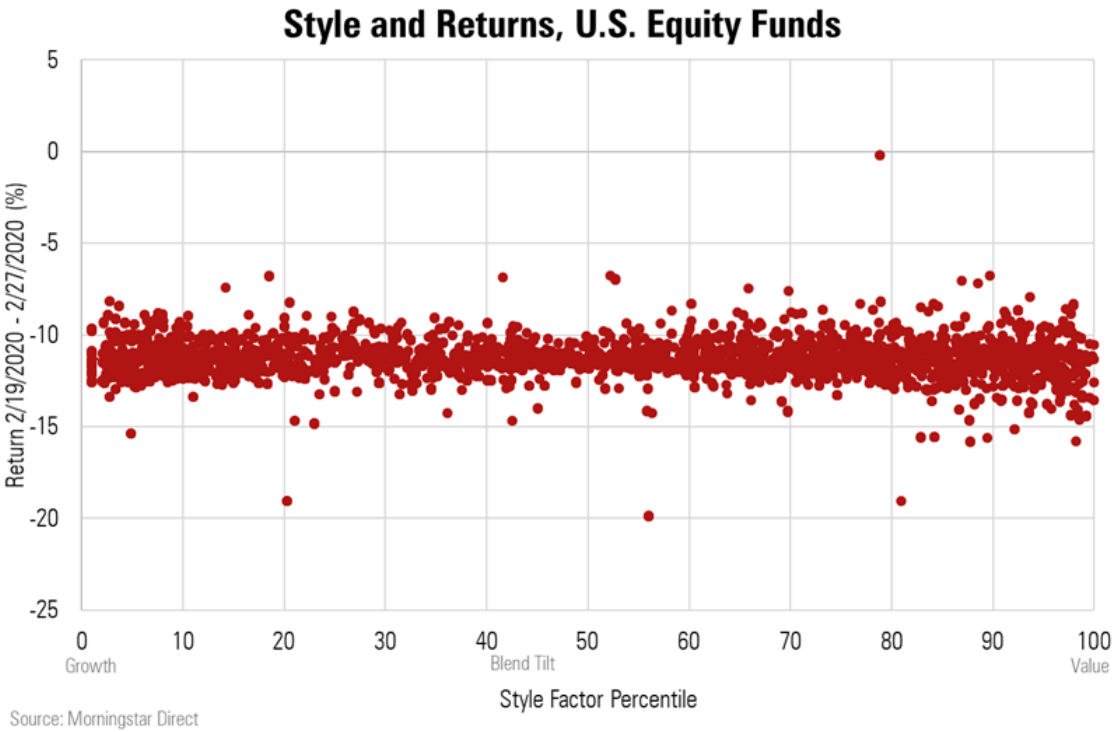


Source: Morningstar Direct

Value Versus Growth

The outperformance of growth strategies over value during the market's bull run has been one of the stock market's most dominant trends in the past three years. Value funds have had only sporadic bouts of outperformance recently, such as during last August's stock market slide, which was sparked by fears of a U.S. recession.

But in the virus sell-off, there's been little distinction.

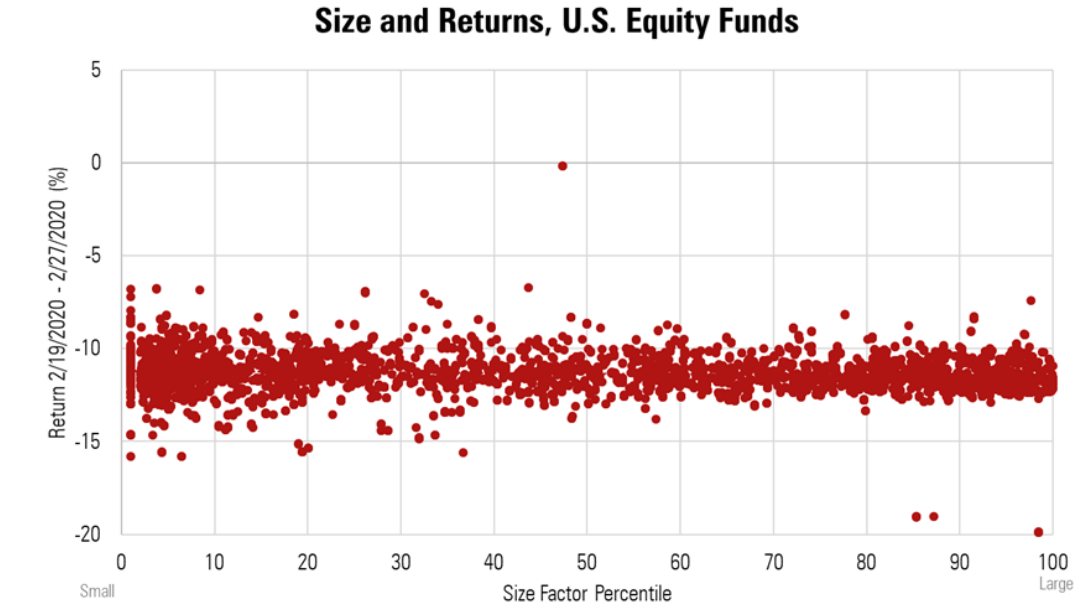


Source: Morningstar Direct

During the Feb. 19-27 time period, value funds posted an average loss of 11.25% versus a 11.11% average drop for growth funds.

Size

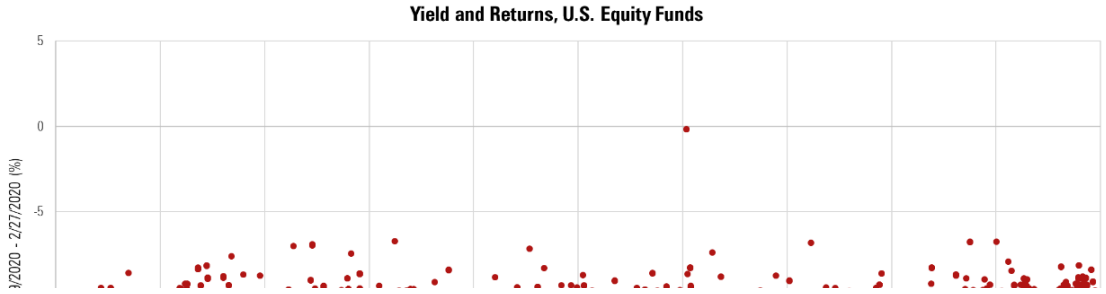
Another clear trend over the past few years has been the outperformance of portfolios with larger-cap stocks. But again, since Feb. 19, on average there was no material differentiation in performance based on market capitalization. Returns of small- and large-cap stocks were nearly identical since Feb. 19, with small caps posting a negative 10.94% return compared with large-cap returns of negative 11.30%.

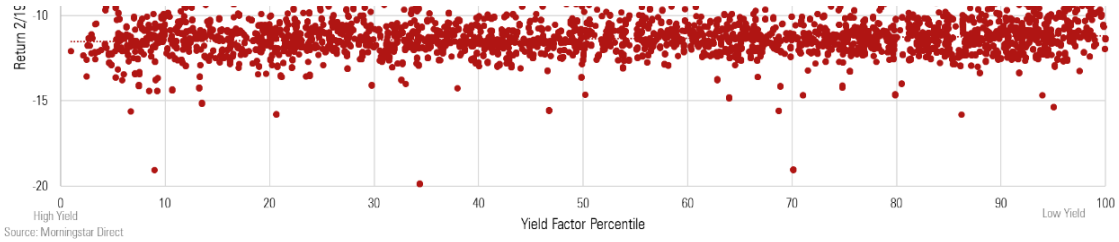


Source: Morningstar Direct

Yield

Yield can often offer investors a safe haven when markets get turbulent. This time around, yield exposure did not affect fund performance.





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MOODY'S
INVESTORS SERVICE

SECTOR COMMENT
6 April 2020

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Regulated Electric and Gas Utilities – US

Dividends a major source of cash if coronavirus downturn is prolonged

Shareholder dividends provide US regulated utilities with a significant source of internal cash that could help them offset the impact of a potentially prolonged coronavirus-related economic downturn. We expect US GDP to contract 2% in 2020, which will include a steep 4.3% contraction in the first half of the year, before recovering to 2.3% growth in 2021 (see "Global Macro Outlook 2020-21 [March 25, 2020 Update]: The coronavirus will cause unprecedented shock to the global economy"). As recessionary indicators build, some utilities will reassess their dividend policy.

In 2019, we estimate US utilities paid out $28.1 billion in shareholder dividends, or almost 70% of aggregate net income. As a critical infrastructure sector, most investors view utilities as an attractive asset class during periods of market volatility. A predictable dividend policy, and effective constituency outreach programs with regulators help contribute to a 10-year average cumulative probability of default that is about four times lower than all non-financial corporates.

Dividends are authorized by a company's board of directors. The disclosure of dividend policies is one of the factors we consider when examining a company's corporate governance practices (see "Non-financial companies – Global: Corporate governance assessments for publicly traded non-financial companies"). We also look at the degree of consistency with which companies comply with its stated dividend policies. That said, the ability to adjust capital dividend payments in response to significant market shocks is a credit positive (see "Utilities and power companies - Corporate governance assessments show generally credit-friendly characteristics").

In a prolonged economic downturn, boards of directors are likely to review dividend plans as an option to conserve cash. We think utilities with high payout ratios are more likely to scale back dividend plans. CenterPoint Energy Inc.(Baa2 stable), which had a payout ratio of 86% in 2019 announced a 48% reduction in its dividend on 1 April 2020 driven primarily by a reduction in cash flow from its Enable Midstream Partners, LP (Baa3 stable) investment. The dividend reduction translates to approximately $275 million in annual savings based on 2019 average shares outstanding. For fiscal year 2019, other utilities with high payout ratios include Dominion Energy Inc. (Baa2 stable), PNM Resources Inc. (Baa3 stable), FirstEnergy Corp. (Baa3 stable) and NiSource Inc. (Baa2 stable).

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Exhibit 1

Utilities paid $28.1 billion in shareholder dividends in 2019, roughly 69% of the $40.9 billion net income

Ranked by 2019 dividend payout ratios ($ millions)

Company	Rating	Outlook	2019 Common Dividend	2019 Net Income	2019 Payout Ratio	2018-2019 YOY Dividend Growth	Expected Growth Guidance for 2020 [1]
Dominion Energy, Inc. [2]	Baa2	Stable	$2,983	$1,341	222%	9.9%	2.5%
PNM Resources, Inc. [3]	Baa3	Stable	$93	$77	120%	8.5%	5.5%
FirstEnergy Corp.	Baa3	Stable	$814	$849	96%	5.6%	3.0%
NiSource Inc.	Baa2	Stable	$299	$328	91%	2.6%	6.0%
CenterPoint Energy, Inc.	Baa2	Stable	$577	$674	86%	3.6%	2.0%
Avangrid, Inc.	Baa1	Negative	$545	$700	78%	0.9%	N/A
Eversource Energy	Baa1	Stable	$663	$909	73%	5.9%	6.0%
Duke Energy Corporation	Baa1	Stable	$2,668	$3,707	72%	3.0%	2.0%
American Electric Power Company, Inc.	Baa1	Negative	$1,350	$1,921	70%	7.1%	3.0%
Evergy, Inc.	Baa2	Stable	$463	$670	69%	11.2%	N/A
OGE Energy Corp.	(P)Baa1	Stable	$299	$434	69%	7.9%	5.0%
Consolidated Edison, Inc.	Baa2	Stable	$924	$1,343	69%	3.5%	3.4%
PPL Corporation	Baa2	Stable	$1,192	$1,745	68%	0.6%	0.6%
Spire Inc.	Baa2	Stable	$119	$179	67%	5.3%	5.1%
WEC Energy Group, Inc.	Baa1	Stable	$745	$1,134	66%	6.8%	7.2%
ALLETE, Inc.	Baa1	Stable	$121	$186	65%	4.9%	6.0%
Otter Tail Corporation	Baa2	Stable	$56	$87	64%	4.5%	5.7%
CMS Energy Corporation	Baa1	Stable	$436	$680	64%	7.0%	7.0%
NextEra Energy, Inc.	(P)Baa1	Stable	$2,408	$3,769	64%	12.6%	12.0%
Edison International	Baa3	Stable	$810	$1,284	63%	2.0%	4.1%
Black Hills Corporation	Baa2	Stable	$125	$199	63%	6.2%	4.4%
Pinnacle West Capital Corporation	A3	Negative	$330	$538	61%	6.1%	6.0%
Alliant Energy Corporation	(P)Baa2	Stable	$338	$557	61%	5.9%	6.0%
DTE Energy Company	Baa2	Stable	$692	$1,167	59%	7.1%	7.0%
Xcel Energy Inc.	Baa1	Stable	$791	$1,372	58%	6.6%	6.2%
Entergy Corporation	Baa2	Stable	$712	$1,241	57%	2.2%	3.7%
Ameren Corporation	Baa1	Stable	$472	$828	57%	3.9%	2.5%
Northwestern Corporation	Baa2	Stable	$115	$202	57%	4.5%	4.3%
ONE Gas, Inc.	A2	Stable	$105	$187	56%	8.7%	7.0%
Public Service Enterprise Group Incorporated	Baa1	Stable	$950	$1,693	56%	4.4%	4.3%
IDACORP, Inc.	Baa1	Stable	$130	$233	56%	6.7%	5.0%
Southwest Gas Holdings, Inc.	Baa1	Negative	$116	$214	54%	4.8%	4.6%
Southern Company (The)	Baa2	Stable	$2,570	$4,739	54%	3.4%	N/A
Avista Corporation	(P)Baa2	Stable	$103	$197	52%	4.0%	4.5%
Unitil Corporation	Baa2	Stable	$22	$44	50%	1.4%	1.4%
Sempra Energy	Baa1	Negative	$993	$2,055	48%	8.1%	8.0%
Atmos Energy Corporation	A1	Stable	$246	$511	48%	8.2%	9.5%
Exelon Corporation	Baa2	Stable	$1,408	$2,936	48%	5.1%	5.0%
Average					**69%**	**5.5%**	**5.0%**
Median					**63%**	**5.4%**	**5.0%**

[1] Based DPS growth guidance or EPS growth guidance and payout ratio target announced before the deterioration in economic conditions
[2] In 2019, Dominion had $1.3 billion in non-cash impairments in addition to roughly $500 million of one-time merger related expenses that reduced net income
[3] Payout ratio elevated due to negative impact on earnings of non-cash impairment associated with the disallowance of certain coal plant upgrade capital
Sources: FactSet, company documents and Moody's Investors Service

From a credit perspective, companies with high payout ratios stand out because the incremental cash outflow for growing dividends requires more financing. Some utilities, such as Dominion and FirstEnergy, indicated a reduction in dividend growth rate before the pandemic, in part to manage their payout ratios down, and reduce their need for incremental debt. For now, most utilities are still holding onto their publicly announced dividend growth guidance. Before the coronavirus outbreak, we were estimating growth in dividends by about 5% in 2020, up to roughly $30 billion from about $28 billion in 2019.

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If the coronavirus-fueled economic recession were to reduce the aggregate net income of US regulated utilities by 10% to $36 billion, from about $40 billion in 2019, the average dividend payout ratio would jump to about 80%.

Slower dividend growth helps future cash flow

We do not expect to see a widespread reduction in utility dividends, but the dividend growth rate could decline materially. Utilities with above-average payout ratios benefit from slower dividend growth, especially if cash flow declines. Of the utilities with high payout ratios, the ones most likely to scale back their dividend plans are those with significant debt balances and little flexibility to cope with cash flow deterioration.

Although the ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt is weighted most heavily in our regulated electric and gas utilities methodology, the next most important ratio is CFO pre-WC less dividends to debt, commonly referred to as retained cash flow (RCF) to debt. The RCF-to-debt ratio provides insight into dividend policies and how management balances the interests of shareholders, fixed-income investors and other stakeholders.

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Exhibit 2

Retained cash flow (CFO pre-WC less dividends) to debt ratios could pressure high dividend payers

Ranked by ratio of (CFO pre-WC) less dividends to debt (2019)

Company	2019 (CFO PreWC - Dividends)	2019 Adjusted Debt	2019 (CFO PreWC - Dividends)/Debt
Edison International	($1,359)	$20,671	-6.6%
PPL Corporation	$1,793	$23,752	7.6%
FirstEnergy Corp.	$1,867	$24,062	7.8%
Dominion Energy, Inc.	$3,276	$40,732	8.0%
Eversource Energy	$1,513	$17,112	8.8%
CenterPoint Energy, Inc.	$1,461	$16,461	8.9%
Avangrid, Inc.	$848	$9,059	9.4%
Southern Company (The)	$4,459	$47,490	9.4%
Consolidated Edison, Inc.	$2,260	$23,902	9.5%
Spire Inc.	$314	$3,289	9.5%
Sempra Energy	$2,651	$27,455	9.7%
NorthWestern Corporation	$235	$2,400	9.8%
American Electric Power Company, Inc.	$3,057	$30,800	9.9%
Entergy Corporation	$2,396	$22,796	10.5%
Avista Corp.	$252	$2,372	10.6%
Duke Energy Corporation	$6,606	$62,105	10.6%
IDACORP, Inc.	$257	$2,349	10.9%
Alliant Energy Corporation	$792	$7,230	11.0%
WEC Energy Group, Inc.	$1,450	$12,935	11.2%
Black Hills Corporation	$406	$3,587	11.3%
NiSource Inc.	$1,198	$10,276	11.7%
Evergy, Inc.	$1,319	$11,167	11.8%
CMS Energy Corporation	$1,343	$11,351	11.8%
ALLETE, Inc.	$214	$1,806	11.9%
NextEra Energy, Inc.	$5,103	$42,303	12.1%
Public Service Enterprise Group Incorporated	$2,102	$17,416	12.1%
Unitil Corporation	$73	$604	12.1%
DTE Energy Company	$2,235	$18,285	12.2%
PNM Resources, Inc.	$426	$3,417	12.5%
OGE Energy Corp.	$473	$3,484	13.6%
Xcel Energy Inc.	$2,679	$19,632	13.6%
ONE Gas, Inc	$269	$1,941	13.8%
Southwest Gas Holdings, Inc.	$461	$3,192	14.4%
Pinnacle West Capital Corporation	$920	$6,150	15.0%
Exelon Corporation	$6,514	$42,843	15.2%
Ameren Corporation	$1,726	$10,334	16.7%
Otter Tail Corporation	$139	$808	17.2%
Atmos Energy Corporation	$825	$4,242	19.4%

Source: Moody's Investors Service

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Utilities view dividend reductions as a last resort

Dividend reductions are uncommon in the utilities sector and companies usually consider them only after taking other credit strengthening measures, such as curtailing discretionary capital expenditures and reducing O&M costs. Nevertheless, during times of market volatility, shifting macroeconomic fundamentals, or company-specific developments that stress liquidity, some utilities have turned to sharp reductions (or suspensions) of their dividend to conserve cash, as shown in Exhibit 5.

Exhibit 3

Historical dividend reductions have been used as a means to conserve cash when necessary

US regulated utility dividend reductions and suspensions since 2008

Company	Year	Previous year payout ratio	% reduction in dividend	Year over year cash savings ($mm) [1]	Primary driver
CenterPoint Energy, Inc.	2020	86%	48%	$275	Underperforming midstream investment
SCANA Corporation	2018	-295%	80%	$135	Abandonment of nuclear project
PG&E Corporation	2017	69%	100%	$1,021	California wildfires
FirstEnergy Corp.	2014	176%	35%	$316	Underperforming unregulated power business
Exelon Corporation	2013	148%	41%	$467	Underperforming unregulated power business
Empire District Electric Company	2011	109%	100%	$25	Service territory devastated by tornado
Ameren Corporation	2009	88%	39%	$196	Unregulated power; challenging business and financial market conditions
Great Plains Energy, Inc.	2009	144%	50%	$62	Economic and financial market uncertainty
Constellation Energy Group, Inc.	2009	-26%	50%	$108	Unregulated power; challenging business and financial market conditions
PNM Resources, Inc.	2008	94%	46%	$13	Underperforming unregulated electric retail business

[1] Represents the difference between total cash dividends paid in the year the dividend reduction took effect and the previous year; CenterPoint estimated based on difference in annualized dividends per share and 2019 average shares outstanding

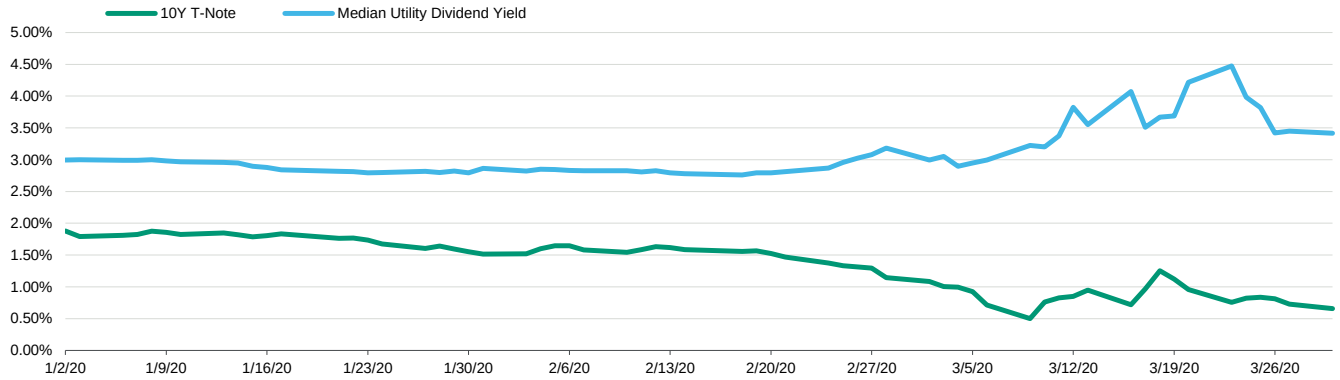
Sources: Company documents and Moody's Investors Service

The recent widening in the spread between 10-year US Treasury yields and the median utility dividend yield indicates a degree of investor uncertainty about the sustainability of dividends. For the companies included in this report, we saw the 2020 year-to-date median dividend yield peak in March at 4.5%, with the dividend yields of CenterPoint and PPL Corporation (Baa2 stable) far exceeding the median at 9.6% and 8.9%, respectively.

Exhibit 4

Widening spread points to investor uncertainty about dividend sustainability

Year-to-date median dividend yield of US utility holding companies and 10-year US Treasury yields as of 30 March 2020



Note: Median utility dividend yield based on the 38 electric and gas utility parent companies identified in this report

Source: FactSet

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Appendix

Exhibit 5

Governance scores for publicly traded North American utilities and power companies

				Voting Rights and Ownership		Related Party Transactions		Compensation Disclosure		Compensation Design		Board Leadership & Independence		Director Qualifications, Experience & Refreshment		Financial Oversight & Capital Allocation 20%		Transparency of Financial Reporting		Audit Quality		Compliance Controls	
Issuer	LT Rating	CGA Assessment	Overall Score	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.	Score	Strength Ind.
AES Corporation, (The)	Ba1	GA-1	3.10	1	Highest	2	Highest	0	Highest	8	Moderate	5	Highest	1	Highest	6	High	0	Highest	0	Highest	3	Highest
ALLETE, Inc.	Baa1	GA-2	3.80	1	Highest	0	Highest	0	Highest	6	High	7	High	8	Moderate	7	Moderate	0	Highest	0	Highest	3	Highest
Alliant Energy Corporation	Baa2	GA-1	3.40	1	Highest	0	Highest	1	Highest	5	High	6	High	7	High	6	High	0	Highest	0	Highest	3	Highest
Ameren Corporation	Baa1	GA-1	3.10	1	Highest	0	Highest	0	Highest	10	Low	7	High	3	Highest	4	Highest	0	Highest	0	Highest	3	Highest
American Electric Power Company, Inc.	Baa1	GA-1	2.83	0	Highest	0	Highest	0	Highest	8	Moderate	3	Highest	2	Highest	7	Moderate	0	Highest	0	Highest	2	Highest
American Water Works Company, Inc.	Baa1	GA-1	3.43	1	Highest	2	Highest	0	Highest	7	Moderate	2	Highest	9	Moderate	6	High	0	Highest	0	Highest	2	Highest
Aqua America, Inc.	Baa2	GA-2	4.16	2	Highest	2	Highest	0	Highest	5	High	9	Moderate	3	Highest	9	Low	0	Highest	1	Highest	3	Highest
Atmos Energy Corporation	A1	GA-2	4.40	0	Highest	1	Highest	0	Highest	9	Moderate	8	Moderate	10	Moderate	7	Moderate	0	Highest	0	Highest	3	Highest
Avangrid, Inc.	Baa1	GA-3	4.70	4	High	1	Highest	0	Highest	5	High	15	Low	4	Highest	7	Moderate	1	Highest	2	High	3	Highest
Avista Corp.	Baa2	GA-1	3.40	1	Highest	0	Highest	1	Highest	6	High	5	Highest	5	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
Black Hills Corporation	Baa2	GA-2	4.10	1	Highest	2	Highest	0	Highest	9	Moderate	9	Moderate	4	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
CenterPoint Energy, Inc.	Baa2	GA-1	3.30	1	Highest	0	Highest	0	Highest	7	Moderate	7	High	2	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
CMS Energy Corporation	Baa1	GA-1	2.33	1	Highest	0	Highest	0	Highest	6	High	6	High	3	Highest	3	Highest	0	Highest	0	Highest	2	Highest
Consolidated Edison, Inc.	Baa2	GA-2	4.03	1	Highest	1	Highest	0	Highest	7	Moderate	6	High	10	Moderate	7	Moderate	0	Highest	0	Highest	2	Highest
Dominion Energy, Inc.	Baa2	GA-1	3.33	1	Highest	1	Highest	0	Highest	5	High	6	High	7	High	6	High	0	Highest	0	Highest	2	Highest
DTE Energy Company	Baa2	GA-2	3.63	1	Highest	2	Highest	0	Highest	8	Moderate	7	High	3	Highest	7	Moderate	0	Highest	0	Highest	2	Highest
Duke Energy Corporation	Baa1	GA-2	3.53	1	Highest	2	Highest	1	Highest	8	Moderate	6	High	2	Highest	7	Moderate	0	Highest	0	Highest	2	Highest
Edison International	Baa3	GA-1	2.90	0	Highest	1	Highest	0	Highest	7	Moderate	1	Highest	4	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
El Paso Electric Company	Baa2	GA-2	4.06	1	Highest	2	Highest	0	Highest	7	Moderate	4	Highest	10	Moderate	7	Moderate	0	Highest	1	Highest	3	Highest
Emera Inc.	Baa3	GA-1	3.00	1	Highest	2	Highest	0	Highest	6	High	1	Highest	4	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
Enbridge Inc.	Baa2	GA-1	3.30	1	Highest	1	Highest	0	Highest	5	High	9	Moderate	1	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
Entergy Corporation	Baa2	GA-2	3.70	1	Highest	0	Highest	0	Highest	9	Moderate	7	High	6	High	6	High	0	Highest	1	Highest	2	Highest
Eversource Energy	Baa1	GA-2	3.93	1	Highest	0	Highest	0	Highest	11	Low	6	High	4	Highest	7	Moderate	0	Highest	0	Highest	5	High
Exelon Corporation	Baa2	GA-1	2.23	0	Highest	0	Highest	1	Highest	7	Moderate	4	Highest	1	Highest	4	Highest	0	Highest	0	Highest	2	Highest
FirstEnergy Corp.	Baa3	GA-1	3.26	1	Highest	2	Highest	0	Highest	3	Highest	5	Highest	7	High	7	Moderate	0	Highest	0	Highest	1	Highest
Fortis Inc.	Baa3	GA-1	2.60	1	Highest	2	Highest	0	Highest	7	Moderate	3	Highest	1	Highest	5	High	0	Highest	0	Highest	3	Highest
IDACORP, Inc.	Baa1	GA-1	3.36	1	Highest	1	Highest	0	Highest	8	Moderate	5	Highest	4	Highest	7	Moderate	0	Highest	0	Highest	1	Highest
NextEra Energy, Inc.	Baa1	GA-1	3.50	0	Highest	1	Highest	0	Highest	5	High	7	High	6	High	7	Moderate	0	Highest	0	Highest	3	Highest
NiSource Inc.	Baa2	GA-2	3.76	1	Highest	0	Highest	0	Highest	8	Moderate	5	Highest	7	High	7	Moderate	0	Highest	1	Highest	3	Highest
NorthWestern Corporation	Baa2	GA-1	2.73	1	Highest	0	Highest	0	Highest	4	Highest	4	Highest	3	Highest	7	Moderate	0	Highest	0	Highest	2	Highest
NRG Energy, Inc.	Ba1	GA-2	3.60	1	Highest	2	Highest	0	Highest	8	Moderate	5	Highest	6	High	6	High	0	Highest	0	Highest	3	Highest
OGE Energy Corp.	(P)Baa1	GA-2	3.93	1	Highest	2	Highest	0	Highest	8	Moderate	9	Moderate	4	Highest	7	Moderate	0	Highest	0	Highest	2	Highest
ONE Gas, Inc	A2	GA-2	3.76	1	Highest	2	Highest	0	Highest	7	Moderate	8	Moderate	3	Highest	7	Moderate	0	Highest	0	Highest	4	High
Otter Tail Corporation	Baa2	GA-1	3.46	2	Highest	0	Highest	0	Highest	6	High	6	High	6	High	6	High	0	Highest	0	Highest	4	High
Pattern Energy Group Inc.	Ba3	GA-1	3.26	0	Highest	1	Highest	0	Highest	6	High	5	Highest	4	Highest	7	Moderate	0	Highest	0	Highest	4	High
Pinnacle West Capital Corporation	A3	GA-1	3.36	1	Highest	0	Highest	0	Highest	5	High	7	High	4	Highest	7	Moderate	0	Highest	0	Highest	4	High
PNM Resources, Inc.	Baa3	GA-1	3.40	1	Highest	0	Highest	0	Highest	8	Moderate	5	Highest	4	Highest	7	Moderate	0	Highest	0	Highest	3	Highest
Portland General Electric Company	A3	GA-1	3.23	0	Highest	2	Highest	0	Highest	4	Highest	4	Highest	7	High	7	Moderate	0	Highest	0	Highest	2	Highest
PPL Corporation	Baa2	GA-1	2.60	0	Highest	2	Highest	0	Highest	7	Moderate	6	High	5	Highest	3	Highest	0	Highest	0	Highest	0	Highest
Public Service Enterprise Group Incorporated	Baa1	GA-2	3.90	0	Highest	1	Highest	1	Highest	7	Moderate	4	Highest	8	Moderate	8	Moderate	0	Highest	0	Highest	3	Highest
Sempra Energy	Baa1	GA-2	3.60	1	Highest	0	Highest	0	Highest	10	Low	6	High	5	Highest	6	High	0	Highest	0	Highest	3	Highest
Southern Company (The)	Baa2	GA-2	3.80	1	Highest	1	Highest	0	Highest	6	High	8	Moderate	6	High	7	Moderate	0	Highest	1	Highest	2	Highest
Southwest Gas Holdings, Inc.	Baa1	GA-2	3.76	1	Highest	0	Highest	0	Highest	6	High	6	High	8	Moderate	7	Moderate	0	Highest	0	Highest	4	High
Spire Inc.	Baa2	GA-1	3.30	1	Highest	0	Highest	0	Highest	6	High	3	Highest	7	High	7	Moderate	0	Highest	0	Highest	3	Highest
TC Energy Corporation	Baa2	GA-2	3.56	1	Highest	4	Moderate	0	Highest	8	Moderate	3	Highest	1	Highest	8	Moderate	0	Highest	0	Highest	4	High
TransAlta Corporation	Ba1	GA-1	3.20	2	Highest	4	Moderate	0	Highest	6	High	4	Highest	2	Highest	6	High	0	Highest	0	Highest	3	Highest
Unitil Corporation	Baa2	GA-1	3.50	0	Highest	0	Highest	0	Highest	4	Highest	9	Moderate	8	Moderate	6	High	0	Highest	0	Highest	3	Highest
Vistra Energy Corp.	Ba1	GA-1	2.86	1	Highest	2	Highest	0	Highest	3	Highest	7	High	3	Highest	6	High	0	Highest	0	Highest	1	Highest
WEC Energy Group, Inc.	Baa1	GA-2	3.93	1	Highest	2	Highest	0	Highest	8	Moderate	5	Highest	8	Moderate	7	Moderate	0	Highest	0	Highest	2	Highest
Xcel Energy Inc.	Baa1	GA-2	3.70	0	Highest	0	Highest	0	Highest	7	Moderate	6	High	8	Moderate	7	Moderate	0	Highest	0	Highest	3	Highest

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- Credit Conditions – Global: Coronavirus and oil price shocks: managing ratings in turbulent times, March 2020
- Regulated electric utilities – North America: Bill proposing fines for power shutoffs is credit negative for California utilities, January 2020
- Regulated electric and gas utilities – US: California's wildfire fund is sufficiently capitalized to pay out claims, November 2019
- Regulated electric and gas utilities – New York: Threat to revoke National Grid's operating license is credit negative for utilities, November 2019

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- Regulated Utilities and Power - US: PG&E bankruptcy highlights environmental, social and governance risks in California, February 2019

Outlooks

- Global Macro Outlook 2020-21 (March 25, 2020 Update): The coronavirus will cause unprecedented shock to the global economy, March 2020
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43 S.Ct. 675
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176
(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

Supreme Court of the United States
BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law 92 298(1.5)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(1.5) k. Public Utilities in General. Most Cited Cases
Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

Constitutional Law 92 298(3)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(3) k. Water and Irrigation Companies. Most Cited Cases
Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness

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of Charges. Most Cited Cases
Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts 170B 504.1

170B Federal Courts
170BVII Supreme Court
170BVII(E) Review of Decisions of State Courts
170Bk504 Nature of Decisions or Questions Involved
170Bk504.1 k. In General. Most Cited Cases
(Formerly 106k394(6))
A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.
Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

***683** Mr. Justice BUTLER delivered the opinion of the Court.
Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684**Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer

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	on. basis of reproduction new, less. depreciation, at prewar prices.	$ 624,548 00
b.	Estimate by company's engineer on. basis of reproduction new, less. depreciation, at 1920 prices.	1,194,663 00
c.	Testimony of company's engineer. fixing present fair value for rate. making purposes.	900,000 00
d.	Estimate by commissioner's engineer on. basis of reproduction new, less. depreciation at 1915 prices, plus. additions since December 31, 1915, at. actual cost, excluding Bluefield. Valley waterworks, water rights,. and going value.	397,964 38
e.	Report of commission's statistician. showing investment cost less. depreciation.	365,445 13
f.	Commission's valuation, as fixed in. case No. 368 ($360,000), plus gross. additions to capital since made. ($92,520.53).	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to 'a,' supra: The commission deducted $204,000 from the estimate (details printed in the margin), [FN1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see 'd,' supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

Difference in depreciation allowed.	$ 49,000
Preliminary organization and development. cost.	14,500
Bluefield Valley waterworks plant.	25,000
Water rights.	50,000
Excess overhead costs.	39,000
Paving over mains.	28,500
	$204,000

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***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. [FN2] This may be compared with its final figure, $460,000.

'The books of the company show a total gross investment,

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. [FN3] The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs.	$14,455	$1,000
2.	Water rights.	50,000	Nothing
3.	Cutting pavements over. mains.	27,744	233
4.	Pipe lines from gravity. springs.	22,072	15,442
5.	Laying cast iron street. mains.	19,252	15,212
6.	Reproducing Ada springs.	18,558	13,027
7.	Superintendence and. engineering.	20,515	13,621
8.	General contingent cost.	16,415	5,448
		$189,011	$63,983

since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of

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$324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:
'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'
'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

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'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).
'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).
'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).
***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.
'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:
'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A

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rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48-50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:
'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. FN4

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.
U.S. 1923
Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176

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P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176
(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

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64 S.Ct. 281
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333
(Cite as: 51 P.U.R.(NS) 193, 64 S.Ct. 281)

Supreme Court of the United States
FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.
Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] **Public Utilities 317A 120**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and Extent in General. Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)
Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] **Public Utilities 317A 123**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of Charges in General. Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)
Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] **Gas 190 14.3(2)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(2) k. Federal Power Commission. Most Cited Cases
(Formerly 190k14(1))
The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. § § 717c(a), 717d(a), 717e.

[4] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[5] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges

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190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] **Gas 190 14.5(7)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(7) k. Presumptions. Most Cited Cases
(Formerly 190k14(1))
An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[8] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[10] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act,

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§ § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] **Gas 190 14.4(4)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(4) k. Method of Valuation. Most Cited Cases
(Formerly 190k14(1))
A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[15] **Gas 190 14.3(4)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(4) k. Findings and Orders. Most Cited Cases
(Formerly 190k14(1))
There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[16] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] **Mines and Minerals 260 92.5(3)**

260 Mines and Minerals
260III Operation of Mines, Quarries, and Wells
260III(A) Statutory and Official Regulations
260k92.5 Federal Law and Regulations
260k92.5(3) k. Oil and Gas. Most Cited Cases
(Formerly 260k92.7, 260k92)
Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and

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Regulation. Most Cited Cases
(Formerly 190k14(1))
The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, § § 4, 6-10, 14, 15 U.S.C.A. § § 717c, 717e-717i, 717m.

[19] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and Regulation. Most Cited Cases
(Formerly 190k14(1))
Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, § § 4, 5, and § 7 as amended 15 U.S.C.A. § § 717c, 717d, 717f.

[20] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, § § 4, 5, and § 7, as amended, 15 U.S.C.A. § § 717c, 717d, 717f.

[21] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[22] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[23] **Federal Courts 170B 452**

170B Federal Courts
170BVII Supreme Court
170BVII(B) Review of Decisions of Courts of Appeals
170Bk452 k. Certiorari in General. Most Cited Cases
(Formerly 106k383(1))
Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] **Constitutional Law 92 74**

92 Constitutional Law
92III Distribution of Governmental Powers and Functions
92III(B) Judicial Powers and Functions
92k71 Encroachment on Executive
92k74 k. Powers, Duties, and Acts Under Legislative Authority. Most Cited Cases
(Formerly 15Ak226)
Congress has entrusted the administration of the

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Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. § § 717 et seq., 717r(b).

[25] **Gas 190 14.5(3)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(3) k. Decisions Reviewable. Most Cited Cases
(Formerly 190k14(1))
Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] **Gas 190 14.5(4)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(4) k. Persons Entitled to Relief; Parties. Most Cited Cases
(Formerly 190k14(1))
Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283 *592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.
***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.
Mr. William B. Cockley, of Cleveland, Ohio, for respondent.
Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.
The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [FN1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [FN2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the

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River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia. sales.	11,000,000
East Ohio.	40,000,000
Peoples.	10,000,000
River.	400,000
Fayette.	860,000
Manufacturers.	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [FN3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell

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Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664-666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' [FN4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. [FN5] The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. [FN6]

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000-approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. [FN7] The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to

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over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription [FN8] of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1] [2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155-157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523-539, 54 S.Ct. 505, 509-517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. [FN9]

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic

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question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3] [4] [5] [6] [7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288**Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast

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array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements,***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] [11] [12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] [14] [15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [FN10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [FN11] No more is required. [FN12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259-288, 50 S.Ct. 123, 128-138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the

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> Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [FN13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [FN14] Secondly, it is pointed out that West Virginia has a production tax [FN15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

> FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

> FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

> FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [FN16]

> FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural

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Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] [17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610**State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. [FN17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. [FN18] These were the types of problems with which those participating in the hearings were pre-occupied. [FN19] Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

611** The Federal Power Commission was given*292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto [FN20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

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[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions [FN21] contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. [FN22] The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. [FN23] But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.
The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

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64 S.Ct. 281
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333
(Cite as: 51 P.U.R.(NS) 193, 64 S.Ct. 281)

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry [FN24] or to protect the interests of those who sell their gas to the interstate operator. [FN25] The return which ****294** the Commission***615** allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. [FN26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21] [22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users [FN27] and domestic consumers. We hardly ***616** can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. [FN28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. [FN29] The ***617** Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. [FN30] But s 4(a) and s 5(a) were not changed. If the standard****295** of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

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FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23] [24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. FN31 However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25] [26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not

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reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' ****296**Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' [FN1] Section 6 [FN2] ****297** throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged

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with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461-466, 10 S.Ct. 462, 702, 703-705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

> FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

> FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard

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by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.
My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as

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an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad,

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bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. FN3

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. FN4 Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. FN5 The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. FN6 Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. FN7 Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, FN8 its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. FN9 Soon monopoly of production or markets developed. FN10 To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. FN11 The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. FN12

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by

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Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. FN13

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. FN14 West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction***633** from this Court. FN15 Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. FN16 That Commission held that a company could not abandon a part of its territory and still serve the rest. FN17 Some courts admonished the companies to take action to protect consumers. FN18 Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. FN19 There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. FN20 Public service commissions of consuming states were handicapped, for they had no control of the supply. FN21

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of

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that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

****303 *634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. [FN22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. [FN23]

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. [FN24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:
Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. [FN25]

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. [FN26] Although this spread is less than ****304** in other parts of the United States, [FN27] it can hardly be said to be

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self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State.	Industrial	Domestic
Illinois.	29.2	1.678
Louisiana.	10.4	59.7
Oklahoma.	11.2	41.5
Texas.	13.1	59.7
Alabama.	17.8	1.227
Georgia.	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. FN28 ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢ ; second 5,000 feet, 45¢ ; third 5,000 feet, 50¢ ; all above 15,000, 55¢ . This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢ ; next 4 m.c.f., 60¢ ; next 8 m.c.f., 55¢ ; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. FN29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. FN30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries, FN31 the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.
In 1915, so it was reported to the Governor of West

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Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' FN32 Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' FN33 While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' FN34 The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' FN35 which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' FN36 And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' FN37

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. FN38 I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery.****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to

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certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' [FN39]

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well

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drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. FN40 Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high. It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.' As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

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***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. FN41

FN41 See 2 Bonbright, Valuation of Property (1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, FN42 and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the

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components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, FN43 is not even ****310** urged by the gas company for valuing its fields.

> FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate

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base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to

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markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. [FN44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? [FN45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313**Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. [FN46] The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural

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gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? FN47 And how much cheaper should industrial***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

> FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.
> 'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If

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Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

U.S. 1944.
Federal Power Commission v. Hope Natural Gas Co.
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333

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BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

January 30, 2020

IN PETITION OF TENNESSEE WATER SERVICE, INC. FOR ADJUSTMENT OF RATES AND CHARGES, APPROVAL OF A QUALIFIED INFRASTRUCTURE INVESTMENT PROGRAM, AND MODIFICATION TO CERTAIN TERMS AND CONDITIONS FOR THE PROVISION OF WATER SERVICE	))))))	**DOCKET NO. 19-00028**

ORDER

This matter came before Chair Robin L. Morrison,[1] Commissioner Herbert H. Hilliard, and Commissioner David F. Jones of the Tennessee Public Utility Commission (the "Commission" or "TPUC"), the voting panel assigned to this docket, during a regularly scheduled Commission Conference held on November 4, 2019, for consideration of the *Petition* filed by Tennessee Water Service, Inc. ("TWS" or "Company") on February 28, 2019 seeking an adjustment of rates and charges, approval of qualified infrastructure investment program, and modification to certain terms and conditions for the provision of water service. TWS amended its *Petition* on March 22, 2019, to remove its request for a Qualified Infrastructure Investment Program.

I. SUMMARY

Setting utility rates is a complicated process entailing the analysis of financial data and the projection of a public utility's revenues, operating expenses, and rate base to arrive at a rate that will allow a utility the opportunity to earn a reasonable rate of return. The rate case process allows for the intervention of interested parties and generally includes the participation of the Tennessee Attorney General's Office, which represents the interests of utility customers through the Consumer

[1] Commission Vice Chair Kenneth C. Hill was originally assigned to the Hearing Panel but recused himself on October 14, 2019. Chair Morrison replaced him. Transcript of Commission Conference, p. 34 (October 14, 2019).

Advocate Unit ("Consumer Advocate"). Rate cases entail a multitude of accounting and financial issues that include troves of documents and thousands of calculations, sponsored by witnesses who are subject to discovery requests and cross-examination. Using the evidentiary record developed by the parties, the Commission sets rates that are just and reasonable. The record of this rate case, as with all matters before the Commission, is available online through the Commission's website for public inspection.

The tragedy and destruction brought by the wildfires in Sevier County, Tennessee, in November of 2016 and its consequences weigh heavily over this matter. There are no known instances within the Commission's history in which a public utility has lost 95% of its customer base and in such a disastrous manner. This is the first instance and, hopefully, the last. Nevertheless, service has been restored at great cost and, in this proceeding, the Commission must look at the facts and financial data before it and set rates.

The Commission has not been blind to the plight of all involved. There have been understandably forthright and emotional appeals from customers about the amount of the rates and matters of insurance coverage. One issue in this matter pertains to what extent, if any, the Company should be penalized for its failure to have an insurance policy that could have at the very least offset some of the extensive damage caused by the wildfires. As explained within this order, the insurance issue has been concluded with the Company forgoing nearly 50% of the cost of the replacement of the under-insured assets.[2] As such, customers will benefit from new assets with a longer and more efficient service life. Furthermore, recovery of the remaining 50% of the Company's investment is spread over sixty-six years. By spreading the cost over a longer period, the burden on customers is lowered considerably. It must be noted here that the decision of the Commission was not unanimous. Commissioner Hilliard did not vote with the majority on the basis

[2] *See* pp. 34-39 of this *Order*, *Section VI, G.10. Regulatory Liability – Uninsured Property.*

that the Company's alleged negligence in not having appropriate insurance entitled the Company to no recovery.[3] To the extent the majority's conclusion on the insurance issue impacted numerous calculations in the majority's revenue deficiency, Commissioner Hilliard did not vote with the majority.

Nevertheless, one must bear in mind that this issue is but one of many considered by the Commission in the context of a rate case. Even assuming the Commission adopted every position of the Consumer Advocate in this matter, including penalizing the Company for 100% of their investment in replacing fire damaged water facilities, the customers of TWS would still face a significant rate increase.

Average Monthly Customer Bill
Under Company and Consumer Advocate Rate Proposals vs. Commission Decision

Company	Consumer Advocate	Commission Decision
$125	$87	$96

Unfortunately, the cost of providing water service is going to be higher when there are fewer customers. A conventional wisdom in ratemaking is that the greater the number of customers, the easier it is to spread and lower the cost of service. Here, the number of customers is far below the level of customers that existed before the wildfires. With time, the number of customers should grow. With other dynamic factors subject to change, it is likely the Company's rates will need to be reviewed in the near future.

[3] Transcript of Commission Conference, pp. 30-31 (November 4, 2019): "Commissioner Hilliard: I voted no primarily because I think the company should have had to put aside the $700,000. I thought their explanation for why they did not adequately insure the facilities was inadequate. I also thought it was very negligent not to insure something at a bare premium where the deductible was higher than what you'd actually get paid if you actually had a loss."

II. BACKGROUND AND *PETITION*

TWS is a public utility subject to the Commission's jurisdiction, providing water service to customers located in the Chalet Village Subdivision ("Chalet Village") in Sevier County, Tennessee. In November 2016, devastating wildfires spread over nearly 180,000 acres throughout Gatlinburg, Tennessee, ultimately claiming fourteen lives. In addition to the tragic loss of life, the wildfires caused devastating property damage to both homes and businesses in the community. TWS had approximately 580 water connections prior to the wildfire, but only 57 remained after the wildfires. The Company, in turn, filed an *Emergency Petition for Emergency Relief* in Commission Docket No. 17-00108. Subsequent to a public hearing and based upon the evidentiary record in that proceeding, the Commission ordered the following:

> Tennessee Water Service, Inc. is authorized to create two regulatory asset accounts to defer: a) actual operating losses beginning January 1, 2017 until its next rate case or otherwise ordered; and b) returns on identified capital projects necessary to repair fire damage and restore the water system to operational status; such returns to be accrued on the actual amount of the capital assets placed into service at Tennessee Water Service, Inc.'s currently-authorized rate of return of 6.89% and beginning on the date the capital asset is placed into service and continuing until its next rate case unless ordered otherwise.
>
> Tennessee Water Service, Inc. is authorized to accrue and defer reasonable and necessary case expenses.
>
> Tennessee Water Service, Inc. shall increase the minimum service charge for all current and future customers by $7. Tennessee Water Service, Inc. is not authorized to charge inactive customers or lot owners the minimum service charge.
>
> The Operational Cost Pass-through Mechanism, as modified by the Consumer Protection and Advocate Division of the Office of the Tennessee Attorney General, is approved.
>
> Tennessee Water Service, Inc. shall file quarterly reports detailing the accounting transactions and account balances for its deferred operating losses, returns on capital assets, rate case expenses, and the amount of quarterly revenues and the amount of aggregate revenues collected from active customers as a result of the minimum service charge increase.

> Tennessee Water Service, Inc. shall file a rate case petition no later than July 1, 2019, unless an order from the Tennessee Public Utility Commission extending this deadline for good cause is obtained.[4]

This *Petition* was filed February 28, 2019 and initially sought a revenue requirement of $469,767, representing a 177% increase over pro-forma rate revenues at present of $169,323.[5] The Company initially sought to increase the minimum monthly charge from $25.70 over a three-year phase in period to $95.00 per month.[6] After the first 1,000 gallons of usage, the Company proposed a three-year phased in volumetric charge of $20.65 per 1,000 gallons.

The Company further proposed a Private Fire Service charge. In addition, the Company sought a Qualified Infrastructure Investment Program ("QIIP") in accordance with Tenn. Code Ann. § 65-5-103 to address a continuing need to maintain and upgrade infrastructure to provide safe and reliable water service.

III. TRAVEL OF THE CASE

The Consumer Advocate filed a *Petition to Intervene* on April 3, 2019. The parties commenced the submission of discovery requests and responses. The Consumer Advocate submitted Pre-filed Testimony of William H. Novak on July 12, 2019, which proposed that a more modest rate increase of approximately $73,000.[7]

On August 30, 2019, TWS filed copies of the legal notices concerning the Hearing date and the proposed rate changes that were published in appropriate newspapers of general circulation, as required by TPUC Rule 1220-4-1-.05.

IV. THE HEARINGS AND POST HEARING FILINGS

The Hearing on the merits of the *Petition* commenced in Nashville and was held on

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[4] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, Ordering Clauses 2-7 (February 21, 2018).
[5] Dante M. DeStefano, Pre-filed Direct Testimony, p. 8 (February 28, 2019).
[6] *Id.* at 4.
[7] William H. Novak, Pre-filed Direct Testimony, p. 8 (July 8, 2019).

September 9, 2019 as noticed by the Commission on August 30, 2019. Participating in the Hearing were the following parties and their respective counsel:

> Tennessee Water Service, Inc. - Ryan Freeman, Esq., Baker, Donelson, Bearman, Caldwell & Berkowitz, P.C., 633 Chestnut Street, Suite 1900, Chattanooga, Tennessee, 37450.
>
> Consumer Advocate Unit – Wayne M. Irvin, Esq. Office of the Tennessee Attorney General, Financial Division, Consumer Advocate Unit, P.O. Box 20207, Nashville, Tennessee 37202-0207.

The panel heard testimony from Company witnesses, Catherine E. Heigel, Dante DeStefano, Anthony Gray, Jared Deason, and J. Bryce Mendenhall. The Consumer Advocate presented witness testimony from William H. Novak. In addition to offering the opportunity for live public comment, a public comment was made telephonically during the Hearing.

Additional filings and pre-filed testimony were submitted before the Hearing Panel reconvened on October 14, 2019, during a regularly scheduled Commission Conference for a supplemental hearing regarding the extent of regulatory liability that is appropriate for TWS.[8] The supplemental hearing was duly noticed on October 1, 2019. At the supplemental hearing, the Hearing Panel heard public comment.

The voting panel assigned to this matter reconvened on November 4, 2019 and deliberated, announcing findings and conclusions upon consideration of the entire record, including all exhibits and the testimony of witnesses. With the exception of a matter concerning a regulatory liability adjustment to account for a lack of proper insurance, the Hearing Panel voted unanimously in favor of the findings and conclusions. Commissioner Herbert Hilliard dissented from a majority of the Hearing Panel with respect to the regulatory liability finding.[9]

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[8] *Pre-Hearing Order*, p. 1 (October 4, 2019).

[9] Transcript of Commission Conference, pp. 30-31 (November 4, 2019). Although Commissioner Hilliard's dissent has a cascade effect on the mathematical conclusions of multiple calculations adopted herein, he does not dissent from the principles and policy decisions applied to the remainder of the issues.

V. CRITERIA FOR ESTABLISHING JUST AND REASONABLE RATES

The Commission has jurisdiction to set the rates of public utilities operating in the State of Tennessee.[10] In setting rates for public utilities, the Commission balances the interests of the utilities subject to its jurisdiction with the interests of Tennessee consumers, i.e., it is obligated to fix just and reasonable rates.[11] A public utility possesses the burden of proof on a petition to prove an adjustment of its rates is warranted.[12]

The Commission must also approve a rate that provides the regulated utility an opportunity to earn a just and reasonable return on its investments.[13] The Commission considers petitions for a rate increase, filed pursuant to Tenn. Code Ann. § 65-5-103, in light of the following criteria:

1. The investment or rate base upon which the utility should be permitted to earn a fair rate of return;

2. The proper level of revenues for the utility;

3. The proper level of expenses for the utility;

4. The rate of return the utility should earn; and

5. Other factors specific to a matter that warrants an investigation to determine the impact on a utility and its rates.

There is no single, precise measure of the fair rate of return a utility is allowed an opportunity to earn. Therefore, the Commission must exercise its judgment in making an appropriate determination. The Commission, however, is not without guidance in exercising its judgment:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return

[10] Tenn. Code Ann. §§ 65-4-101(6); 65-4-104; 65-5-101, *et seq.*
[11] Tenn. Code Ann. § 65-5-101 (2018).
[12] Tenn. Code Ann. § 65-5-103(a) (2018).
[13] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 43 S.Ct. 675 (1923).

> should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[14]

In addition, the United States Supreme Court has determined that regulated utilities are entitled to a return that is "just and reasonable."[15] The rate a utility is permitted to charge should enable it "to operate successfully, to maintain its financial integrity, to attract capital, and to compensate investors for the risks assumed."[16]

The general standards to be considered in establishing the fair rate of return for a public utility are financial integrity, capital attraction and setting a return on equity that is commensurate with returns investors could achieve by investing in other enterprises of corresponding risk.[17] Thus, rates established must allow a company to cover its operating expenses and provide an opportunity to earn a fair rate of return on a company's investment used to provision service. Further, a rate should be reasonable not only when it is first established, but also for a reasonable time thereafter.[18]

The Commission has wide discretion with regard to setting rates. The Commission may "utilize an historical test period, a forecast period, a combination of these where necessary, or any other accepted method of rate making necessary to give a fair rate of return."[19] The Supreme Court noted in *Powell Tel. Co. v. Tennessee Pub. Serv. Comm'n* that, "there is no statutory nor decisional law that specifies any particular approach that must be followed by the Commission. Fundamentally, the establishment of just and reasonable rates is a value judgment to be made by the Commission in the exercise of its sound regulatory judgment and discretion."[20] Accordingly, the

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[14] *Id.* at 692-693; *see also Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989).
[15] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 591, 605 (1944).
[16] *Id.*
[17] *Id.* at 603.
[18] *McCardle v. Indianapolis Water Co.*, 272 U.S. 400, 408-409, 47 S.ct 144, 148 (1926); *Southern Bell Telephone & Telegraph Co. v. Tennessee Pub. Serv. Comm'n*, 304 S.W2d 640, 647 (1944).
[19] *Powell Tel. Co. v. Tennessee Pub. Serv. Comm'n,* 660 S.W.2d 44, 46 (Tenn.1983); *Am. Ass'n of Retired Persons v. Tennessee Pub. Serv. Comm'n,* 896 S.W.2d 127, 133 (Tenn.Ct.App.1994).
[20] *Powell*, 660 S.W.2d at 46.

Commission is not limited to adopting any particular approach or to adopting a specific test period in making known and measurable adjustments to produce just and reasonable rates.[21]

Applying these principles and criteria, and upon consideration of the entire record, including all exhibits and the testimony of the witnesses, the panel made the following findings and conclusions. It should be noted here that some calculations contain numbers rounded to the nearest whole number.

VI. FINDINGS AND CONCLUSIONS

A. TEST PERIOD AND ATTRITION PERIOD

In a rate case, the Commission must decide the appropriate test period and attrition period to be utilized in the calculation of rates. Selecting the test period has the stated purpose of providing an indication of the rate of return that will be produced during the period under the existing rate structure in the reasonably foreseeable future. The test period takes into consideration the effect of calculations related to revenues, expenses, and investments.

The Company selected a historical test period of the twelve months ending September 30, 2018 and an attrition period of the twelve months ending December 31, 2020. The Consumer Advocate adopted the same review periods.[22] However, the Consumer Advocate also utilized monthly data for the three-year period ended September 30, 2016 to form a "pre-fire" snapshot for analysis in order to properly consider the impact of the significant impact on the wildfires such as loss of customers.[23] The panel voted unanimously to adopt the attrition period of the twelve months ending December 31, 2020.

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[21] *CF Industries v. Tennessee Pub. Serv. Comm'n,* 599 S.W.2d 536, 543 (Tenn. 1980).
[22] William H. Novak, Pre-filed Direct Testimony, p. 6 (July 12, 2019).
[23] *Id.* at 6-7.

B. REVENUES

The primary difference between the parties' water sales forecasts is the application of the tariff's base charge to water usage. The Company's forecast is based on providing customers with up to 2,000 gallons of water per month in the base charge per the Company's current billing practice; however, the Consumer Advocate includes only 1,000 gallons in the base charge per the Company's tariff.[24] The Company has been incorrectly applying its tariff rate by implementing the $25.70 monthly charge for the first 2,000 gallons of water rather than the first 1,000 gallons of water. As a result, the Company has been under-collecting from customers by $6.30 per customer monthly dating back to the implementation of the emergency rate order in Docket No. 17-00108.[25] Another material difference is that the Consumer Advocate projects monthly customer usage that is 601 gallons (4,080 – 3,479) more than the Company's, which is based on normalized, pre-fire water sales for the three years ended September 30, 2016.[26]

The Hearing Panel concluded that the Consumer Advocate's corrected water sales forecast should be adopted because the forecast is based upon the correct application of the Company's current tariff, and it reflects normalized, pre-fire water usage and water loss rates. As such, the Commission forecasts Attrition Year Water Sales at present rates of $248,782, which is $78,370 more than the Company's water sales forecast of $170,412.

With respect to the category of "Other Revenue", the Company did not originally include any amount for Other Revenue, but it subsequently amended its case to adopt the Consumer Advocate's forecast of Other Revenue for the Attrition Year. The Consumer Advocate projected Other Revenue of $4,919, based upon the average Other Revenue per bill for the three years ended September 30, 2016, and applied this average to the projected customer bills for the Attrition Year.

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[24] *Id.* at 12.
[25] *Id.*
[26] *Id.* at 12-13.

The Hearing Panel found that the Consumer Advocate's calculations were reasonable and accurate for projection of Other Revenue at present rates. Additionally, the Company agrees with the Consumer Advocate's forecast. Based on corrections to water sales, the panel voted unanimously to adopt a forfeited discount rate of 1.4773% ($3,675/$248,782).

C. Operations and Maintenance Expenses

For the Company's Operations and Maintenance Expenses, the Company forecasted $224,451 and Consumer Advocate forecasted $141,752. The Hearing Panel adopted a forecast of $141,466. The table below provides a breakdown of these expenses, followed by an examination of each expense listed.

	Company	Consumer Advocate	Commission Decision
Purchased Power	$ 8,723	$ 8,527	$ 8,667
Maint. & Repair	50,190	23,240	23,622
Maint. Testing	1,920	1,876	1,908
Chemicals	243	111	241
Transportation	2	5	2
Outside Services	5,842	1,986	5,829
Office Supplies	2,954	2,882	2,935
Pension Benefits	6,924	6,769	6,880
Rent	2,047	1,492	2,037
Insurance	3,401	3,324	3,379
Office Utilities	2,386	1,575	2,370
Miscellaneous	1,525	1,431	1,515
Purchased Water	116,937	60,295	61,301
Bad Debt	1,187	600	610
Regulatory	0	0	0
Salary & Wages	20,170	27,639	20,170
Total	$224,451	$141,752	$141,466

C.1. Purchased Power, Maintenance Testing, Transportation, Office Supplies, Pension Expenses, Insurance, and Miscellaneous Expenses

With respect to Purchased Power; Maintenance Testing; Transportation; Office Supplies; Pension Benefits; Insurance; and Miscellaneous, the Company determined the three-year, pre-fire average amount for the three years ended September 30, 2016, and, using the midpoint of the Test

Year to the midpoint of the Attrition Year, it inflated the pre-fire average amount for 27 months (7.58%) and divided by the three-year average number of customers to determine an expense amount per customer.[27] The per-customer amount was then multiplied by a projected 313 customer count to arrive at the Attrition Year forecast.[28]

The Consumer Advocate also used the same three-year, pre-fire average as a basis to forecast these expense categories; however, it used the end of the Test Year to the midpoint of the Attrition Year to inflate the pre-fire average amount by 21 months (5.85%) in order to compute its expense amount per customer.[29] The per-customer amount was then multiplied by a projected 311 customer count to arrive at the Attrition Year forecast. Both the Company and the Consumer Advocate used a 3.3% CPI as an annual inflator. The difference in growth rates is due to the Company starting at the midpoint of the Test Year and inflating for 27 months to arrive at a compounded growth rate of 7.58%; whereas, the Consumer Advocate started at the end of the Test Year and inflated for 21 months to arrive at a compounded growth rate of 5.85%. [30]

The pre-fire average is farther removed in time than the typical, most-recently completed test year generally employed in rate cases. Under the unique facts of this case, the Hearing Panel found such methodology necessary here and the Company's compounded growth rate to be reasonable. Due to ongoing fire recovery efforts in 2017 and 2018 affecting routine operations, both parties normalize the test period by developing a pre-fire, three-average for 2014 through 2016 for purchased power, maintenance testing, transportation, office supplies, pension benefits, insurance, and miscellaneous expenses. The Hearing Panel concluded the pre-fire average amounts to be a reasonable basis for projecting these expenses for the Attrition Year. It should be noted that the differences in the parties' methodology here are not significant. For all the expense categories

[27] Anthony Gray, Pre-filed Direct Testimony, p. 3-4 (February 28, 2019).
[28] *Id.*
[29] William H. Novak, Pre-filed Direct Testimony, p. 7, fn 8. (July 12, 2019).
[30] *Id.*

discussed here, the Company projects a total of $25,449, as compared to the Consumer Advocate's $24,814; a difference of only $635 for all of the aforementioned expenses combined.

Based on this analysis, the Commission utilized a forecast for each of these expense categories by applying the compounded growth rate of 7.58% to the pre-fire averages to compute an expense amount per customer, and then multiplied that amount by 311 customers projected for the Attrition Period to arrive at the expense forecast. Accordingly, the Hearing Panel voted unanimously to adopt expenses in the following amounts: Purchased Power of $8,667, Maintenance Testing of $1,908, Transportation of $2; Office Supplies of $2,935; Pension Benefits of $6,880; Insurance of $3,379; and Miscellaneous Expense of $1,515.

C.2. Maintenance and Repair Expenses

With respect to Maintenance and Repair expenses, the Company used a per-customer average of selected maintenance accounts for the three years ended September 30, 2016, inflated for 27 months (7.58%), and applied to projected Attrition Year customers of 311 to determine a portion of its forecast.[31] The Company then added the booked contract operator expense for the year ended September 30, 2018 to this amount to arrive at its total Attrition Year forecast of $50,173 for Maintenance and Repair. After the Hearing, the Company submitted a revised forecast of 50,190, which was based on Attrition Year customers of 313 as opposed to the 311 included in its original forecast.[32]

The Consumer Advocate used a three-year average of individual maintenance accounts inflated for 21 months (5.85%) to determine an Attrition Year amount of $23,240.[33] The Company projected $26,950 more than the Consumer Advocate. The primary difference between the Company and the Consumer Advocate is the amount forecasted for contract operator expense. The

[31] Anthony Gray, Pre-filed Direct Testimony, p. 3 (February 28, 2019).
[32] Tennessee Water Service's Late Filed Exhibits, Exhibit 6, Schedule 7 (September 10, 2019).
[33] William H. Novak, Pre-filed Testimony, pp. 13-14 (July 12, 2019).

Consumer Advocate used a pre-fire, three-year average of $20,893 to normalize this expense, whereas the Company used the 2018 Test Year ended September 30, 2018, amount of $47,444 for its basis.[34]

The Hearing Panel found that post-fire restoration of the water system is largely complete and the pre-fire average is more reflective of Maintenance and Repair expense on a going-forward basis; thus, Maintenance and Repair expense should return to pre-fire normalized amounts. Much of the system has been rebuilt and replaced with new plant. As such, it is reasonable to expect a downward trend in Maintenance and Repair expense over the next few years. Based on using the pre-fire average inflated by the Company's forecasted growth of rate of 7.58%, the Hearing Panel voted unanimously to adopt $23,622 as the Maintenance and Repair expense for the Attrition Year.

C.3. Chemicals and Office Utilities

Like most of its other expense projections, the Company determined the three-year, pre-fire average amount for the three years ended September 30, 2016, and inflated the pre-fire average for 27 months (7.58%) and divided by the three-year average number of customers to determine the expense amount per customer. The per-customer amount was then multiplied by a projected 313 customer count to arrive its Attrition Year forecast of Chemicals of $243 and Office Utilities of $2,386.[35] The Consumer Advocate, however, used the post-fire test year ended September 30, 2018, as its basis for projecting one account comprising the Chemicals expense and one account comprising the Office Utilities expense.[36] Other than pointing out that the landscaping expense dropped significantly during the test period, the Consumer Advocate did not explain why it used the

[34] *Id.*
[35] Anthony Gray, Pre-filed Direct Testimony, p. 3 (February 28, 2019).
[36] William H. Novak, Pre-filed Direct Testimony, CA Exhibit, Schedule 7 (July 12, 2019).

post-fire amounts for these two accounts as opposed to the pre-fire average it used for all the other accounts which make up these expense categories.[37]

Here, the Hearing Panel found it reasonable and consistent to use the pre-fire average for all accounts. Therefore, the Chemicals and Office Utilities expense forecasts was computed by inflating the pre-fire average by 7.58% to determine a per-customer amount and then multiplying that amount by 311 customers projected for the Attrition Year. Based on this calculation, the Hearing Panel voted unanimously to adopt Chemicals expense of $241 and Office Utilities expense of $2,370.

C.4. Outside Services and Rent

With respect to Outside Services and Rent, the Company based its forecasts on the three-year, pre-fire average amount inflated by 7.58% just as it did with most of its other expenses. However, the Company added pro-forma adjustments for these two expense categories. The Company made pro-forma adjustments to reflect an estimated corporate allocation of Outside Services and estimated new corporate office rent, neither of which was included in the test period. As adjusted to reflect these pro-forma items, the Company forecasted Outside Services of $5,842 and Rent of $2,047.[38] The Consumer Advocate used a three-year, pre-fire average inflated by 5.85% to determine an Attrition Year forecast of $1,986 for Outside Services and $1,492 for Rent.[39] The primary differences between the Company and the Consumer Advocate are the pro-forma adjustments added by the Company.

The Hearing Panel found the pro-forma adjustments for Outside Services and Rent appear reasonable and reflect known and measurable adjustments. Using a forecast based on a three-year, pre-fire average inflated by 7.58%, as applied to projected Attrition Year customers of 311, to arrive

[37] *Id.* at 16.
[38] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 7, (September 10, 2019).
[39] William H. Novak, Pre-filed Direct Testimony, p. 14 (July 12, 2019).

at Outside Services of $2,041 and Rent of $1,517 with the addition of the Company's pro-forma adjustments, the Hearing Panel voted unanimously to adopt Outside Services of $5,829 and Rent of $2,037.

C.5. Purchased Water

With respect to Purchased Water, in projecting Attrition Year expense the Company computed the average per-customer purchased water for the year ended September 30, 2018, inflated by 7.58%, and multiplied by an annual customer count of 311 to arrive at an Attrition Year forecast of $116,937. Embedded in this amount is a lost and unaccounted for water rate of 71.52%. The Consumer Advocate computed the average per-customer purchased water for the three years ended September 30, 2016, inflated that amount by 5.85%, and applied the projected customer count of 311 to arrive at $60,295 of purchased water expense for the Attrition Year.[40] Embedded in the Consumer Advocate's forecast is an average lost and unaccounted for water rate of 14.83%.

The Company's purchased water forecast is 94% greater than the Consumer Advocate's. The primary difference is the much higher water loss rate included in the Company's forecast. The Company's use of the test year ended September 30, 2018, likely explains the higher water loss rate than the pre-fire rate assumed by the Consumer Advocate. During the Company's test year, the system was still undergoing major fire damage repairs and recovery. Since those recovery efforts are largely completed, water loss rates during the Attrition Year should normalize to pre-fire levels. Indeed, since much of the system has been replaced with new plant, it is reasonable to assume that future water loss rates should decline over historic levels. For these reasons, the Hearing Panel accepted the Consumer Advocate's methodology for computing purchased water with the application of an inflation factor of 7.58% to the pre-fire average. Thus, the Hearing Panel voted unanimously to adopt Purchased Water of $61,301 for the Attrition Year.

[40] *Id.*, at 18.

C.6. Bad Debt Expense

With respect to Bad Debt, the Company projected bad debt based upon the booked amount for the year ended September 30, 2018, expressed as a percentage of water sales for the same period, and it then applied this percentage to its projected water sales for the Attrition Year to arrive at $1,187. The Consumer Advocate used the per-customer average for the three years ended September 30, 2016, inflated by 5.85% and multiplied by the projected customer count of 311 to arrive at its Attrition Year forecast of $600. Staff reviewed the calculations of both parties and found them to be accurate. A concern here is the Company's projection essentially doubled the historic average of bad debt expense. No evidence was offered to support such a sharp increase in bad debt expense over historic pre-fire levels. Here, the methodology of the Consumer Advocate, which normalizes the forecast based on pre-fire operations, provides a reasonable and acceptable basis for determining Attrition Year bad debt expense. For these reasons, the Hearing Panel voted unanimously to adopt Bad Debt expense of $610 for the Attrition Year.

C.7. Salary and Wages

With respect to Salary and Wages, the Company projected salary and wages based upon the amounts booked for the year ended September 30, 2018, reduced by a non-recurring amount and by capitalized labor to arrive at its Attrition Year forecast of $20,170. The Consumer Advocate used a three-year, pre-fire average inflated by 5.85%, and applied to the Attrition Year customer count of 311 to arrive at its Salary and Wage forecast of $27,639.[41] The Consumer Advocate did not reduce its forecast to reflect capitalized labor.

The panel found that the Company's projection is based on a more recent booked amount that better reflects current employee levels while also recognizing adjustments for non-recurring

[41] William H. Novak, Pre-filed Direct Testimony, p. 19 (July 12, 2019).

and capitalized labor amounts. Therefore, the Hearing Panel voted unanimously to adopt Salaries and Wages of $20,170 for the Attrition Year.

D. Depreciation and Amortization Expenses

Below is a table outlining each party's forecast and the Commission's decision with respect to Depreciation and Amortization Expenses:

	Company	Consumer Advocate	Commission Decision
Depreciation	$ 42,735	$ 42,735	$ 42,735
Amortz. CIAC	15,213	15,213	15,213
Amortz. Excess Deferred Taxes	2,245	2,769	2,769
Amortz. ITC	48	48	48
Amortz. Deferred Operating Losses	41,788	20,894	20,894
Amortz. Deferred Return on Incremental Plant	17,298	8,649	5,757
Amortz. Deferred Rate Case Cost	17,940	17,940	20,638
Amortz. Uninsured Property	5,730	11,619	5,730
Total	$ 107,985	$ 107,985	$ 66,264

D.1. Depreciation Expense

With respect to Depreciation Expense, the Company originally projected $39,613 for Depreciation Expense; in its Late-Filed Exhibit, however, the Company agreed with the Consumer Advocate's projected $42,735 Depreciation Expense.[42] The Consumer Advocate began with December 2019 depreciation expense in the amount of $3,239 based on a balance of $2,590,658. Thereafter, the Consumer Advocate applied .13% to the average balance to determine the monthly depreciation for the Attrition Year. The twelve-month total is $42,735. The Hearing Panel voted unanimously to adopt Depreciation Expense for the Year in the amount of $42,735.

[42] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 6 (September 10, 2019).

D.2. Amortization of Contributions in Aid of Construction

With respect to Amortization of Contributions in Aid of Construction, the Company and the Consumer Advocate projected the Attrition Year expense based upon the twelve month amortization ($1,268 * 12) of this account resulting in an Amortization expense of $15,213. The Hearing Panel found the calculations were accurate and corresponded to the amortization utilized in determining the Attrition Year Contribution in Aid of Construction balance. For these reasons, the Hearing Panel voted unanimously to adopt $15,213 as the Amortization of Contributions in Aid of Construction.

D.3. Amortization of Regulatory Liability Excess Deferred Taxes

With respect to Amortization of Regulatory Liability Excess Deferred Taxes, the Company adopted in a late-filed exhibit the amount of $2,245. The Consumer Advocate projected the Attrition Year balance to be $2,769. The Hearing Panel found the Consumer Advocate's calculations to be accurate and the amortization correlates to the Regulatory Liability Excess Deferred Tax projected balance of $71,917 adopted by both parties. For these reasons, the Hearing Panel voted unanimously to adopt $2,769 for the Amortization of Regulatory Liability Excess Deferred Taxes.

D.4. Amortization of Investment Tax Credits

With respect to the Amortization of Investment Tax Credits, both the Company and the Consumer Advocate agree on the Attrition Year amount of $48. This amount is based upon an amortization of $4.00 per month being applied to the unamortized investment tax credit balance. The Hearing Panel found the calculations to be accurate and voted unanimously to adopt $48 as the Amortization of Investment Tax Credit for the Attrition Year.

D.5. Amortization of Deferred Operating Losses

In Commission Docket No. 17-00108, the Company was authorized to establish a regulatory account to defer operating losses.[43] Additionally, the Commission delayed setting an amortization period until the Company's rate proceeding where recovery would be addressed.[44]

Both parties agree on the Deferred Operating Loss balance at the end of the Test Year of $208,941. The difference between the parties for this expense is the Company amortized this amount over five years, while the Consumer Advocate amortized this amount over ten years. Whether to amortize for five or ten years or any period is a matter of reasonableness may be employed to prevent or lessen rate shock to consumers. Here, ratepayers are burdened with significant additional cost resulting from the wildfires and the longer amortization period minimizes the monthly bill increase. For this reason, the Hearing Panel found a ten-year amortization period for Deferred Operating Loss to be appropriate and voted unanimously to adopt Amortization of Deferred Operating Losses of $20,894.

D.6. Amortization of Deferred Return on Incremental Plant

Both parties agree on the Deferred Return on Incremental Plant balance at the end of the Test Year of $86,486, with the Company recommending an annual amortization of $17,297, and the Consumer Advocate recommending $8,648.[45] The reason for the difference between the parties for this amortization expense is the Company amortized this amount over five years, while the Consumer Advocate chose a ten-year amortization period.

Imputing the Company's proposed regulatory liability amount of $382,016 and recalculating the deferred returns using the same methodology as the parties, the Deferred Return on Incremental Plant balance at the end of the Test Year is $57,574. Taking into consideration the rate impact on

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[43] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, p. 10 (February 21, 2018).
[44] *Id.*
[45] William H. Novak, Pre-filed Direct Testimony, p. 32 (July 12, 2019).

customers, particularly the burden of significant additional costs resulting from the wildfires, a longer amortization period which minimizes the monthly bill increase is reasonable. Therefore, the Hearing Panel voted unanimously to adopt a ten-year amortization period for Deferred Return on Incremental Plant as appropriate and Amortization of Deferred Return on Incremental Plant of $5,757.

D.7. Amortization of Deferred Rate Case Costs

The Company originally proposed $21,691, however, the Company later agreed with and adopted the Consumer Advocate's projected $17,940 for the Attrition Year.[46] The Consumer Advocate based its projection on costs of $30,000 as cap in Commission Docket No. 17-00108 plus an estimated cost of $59,700 for this docket with a five-year amortization period.[47] The Company has supplemental rate case expense of $13,488[48] in this case and amortized this amount over five years as well to bring the total annual amortization to $20,638. The Hearing Panel found that considering TWS is a small company and that there was more than one hearing, along with the complex facts of this case, allowing recovery of the supplemental rate case expense is reasonable. For these reasons, the Hearing Panel found the five-year amortization period of rate case cost to be appropriate and voted unanimously to adopt $20,638 as Amortization of Deferred Rate Case Costs for the Attrition Year.

D.8. Amortization of Uninsured Property

With respect to the Commission's finding of a Regulatory Liability for Uninsured Property by taking the Company's proposed amount of $382,016, a Majority of the Hearing Panel voted that this amount shall be amortized over 66.67 years (1.5% amortization rate) through the Attrition Year

[46] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 6 (September 10, 2019).
[47] William H. Novak, Pre-filed Direct Testimony, p. 33 (July 12, 2019).
[48] *TWS Supplemental Hearing Costs Filing*, (October 17, 2019).

to arrive at the midpoint balance of $8,041 of accumulated amortization and annual amortization expense of $5,730 ($382,016 * 1.5%). [49]

E. General Taxes

General Taxes consist of Payroll, Franchise, Gross Receipts, Property and Commission Regulatory Fees. The chart below provides a breakdown of the General Taxes category, the positions of the parties, and the decision of the Commission.

	Company	Consumer Advocate	Commission Decision
Payroll	$ 1,940	$ 723	$ 1,940
Franchise	1,792	1,122	1,122
Gross Receipts	3	144	144
Property	15,139	18,188	18,188
Utility Commission	0	267	1,054
Total	$ 18,874	$ 20,444	$ 22,448

E.1. Payroll Taxes

The Company's projected Salary & Wage expense of $20,170 is based upon the booked amount for the year ended September 30, 2018. The corresponding payroll tax general ledger amount at September 30, 2018 was adjusted consistent with the Salary and Wage adjustment to arrive at an Attrition period expense of $1,940. The Consumer Advocate based its projection of $723 upon the average of pre-fire years and inflated for 21 months (5.85%).[50] The Company's forecast corresponds to payroll tax general ledger amount at September 30, 2018 and was adjusted consistent with the Salary and Wage adjustment. For this reason, the Hearing Panel voted unanimously to adopt the Company's projected Payroll Expense of $1,940.

E.2. Franchise Tax

The Company projected $1,792 franchise taxes using the same amount of the Test Year ending September 30, 2016. The Consumer Advocate calculated the per customer average

[49] *See* Findings with respect to Rate Base in Section *G.9. Regulatory Liability – Uninsured Property* of this Order. Commissioner Hilliard dissented from the Majority decision with respect to the amount of the regulatory liability.
[50] William H. Novak, Pre-filed Direct Testimony, p. 21 (July 12, 2019).

franchise tax based up FY 14-15-16 ($3.41) times the number of customers (311) times the 21-month inflation factor of 5.85% to determine franchise taxes of $1,122 and more accurately reflect an appropriate level of Attrition Period expense. For this reason, the Hearing Panel voted unanimously to adopt $1,122 as Franchise Taxes for the Attrition Year.

E.3. Gross Receipts Tax

The Company projected the gross receipt tax year amount of $3 based solely on the Test Year amount. The Consumer Advocate calculated the Test Year average per customer of $0.44 times the number of customers (311) times the 21-month inflation rate of 5.85% to arrive at $144. The Consumer Advocate's methodology and calculation more accurately reflect an appropriate level of Attrition Year expense. For this reason, Hearing Panel voted unanimously to adopt $144 as Gross Receipts tax for the Attrition Year.

E. 4. Property Tax

The Company used the general ledger amount for the real estate tax account ($8,383) and the general property tax account balance ($6,757) for the operating company and the parent at September 30, 2018 to calculate $15,139 in property taxes for the Attrition Year. The Consumer Advocate used the post-fire average per customer for general taxes times the customer count of 311 ($9,804) to determine general property taxes. Real estate taxes ($8,383) were based solely on the booked amount for the October 1, 2017 to September 30, 2018. The total Attrition Year taxes are projected to be $18,188.

Here, the panel found the methodology used by the Consumer Advocate is preferable because it is based upon a customer count which should be more reflective of actual costs. For this reason, the Hearing Panel voted unanimously to adopt $18,188 for Property Tax Expense for the Attrition Year.

E. 5. Inspection Fees

The Company projected zero for Inspection fees and the Consumer Advocate projected $267.[51] Pursuant to Tenn. Code Ann. §65-4-303, regulatory inspection fees are based upon the gross receipts, before any deductions, of the previous year. In its *Petition,* the Company listed Test Year revenues of $86,295 and the Consumer Advocate listed Test Year revenues of $86,299. The Company under-billed customers for the previous year, due to the mis-application of their tariff. The Company should take greater care in applying its tariff correctly. For this reason, Hearing Panel calculates the inspection fee of $1,054 based upon the projected Attrition Year revenues of $253,701, less bad debt expense of $610. (($248,782-$610-$5,000)/1,000) *$4.25).

F. State Excise and Federal Income Taxes

Excise Taxes are calculated by applying the statutory rate of 6.5 % to Net Income before Federal Income Taxes. Federal Income Taxes are calculated by applying the statutory rate of 21% to Net Income less Excise Taxes. Based upon the Net Income adopted by the Hearing Panel, State Excise Taxes of negative $783 and Federal Income Taxes of negative $2,366 are adopted for the Attrition Year.

G. Rate Base

Rate Base is the total of the investor funded or supplied plant, facilities, and other investments used by the utility in provisioning service to its customers. Thus, Rate Base represents the investment on which a fair rate of return is applied to arrive at the net operating income requirement. The following table presents the comparative Rate Base calculations of the Company, the Consumer Advocate, and the Hearing Panel's decision:

[51] William H. Novak, Pre-filed Direct Testimony, p. 21 (July 12, 2019).

Attrition Year	Company	Consumer Advocate	Commission Decision
Additions:			
Utility Plant In Service	$ 2,624,827	$ 2,624,827	$ 2,624,827
Working Capital	15,798	12,612	12,827
Deferred Operating Losses	198,494	198,494	198,494
Deferred Return on Incremental Plant Investment	82,162	82,162	54,695
Deferred Rate Case Cost	80,730	80,730	92,869
Total Additions	$ 3,002,011	$ 2,998,825	$ 2,983,712
Deductions:			
Acc. Depreciation	$ 436,926	$ 436,926	$ 436,926
CIAC	633,347	633,347	633,347
Acc. Deferred Income Taxes	57,687	57,687	57,687
Reg.Liability - Excess Deferred Taxes	71,917	71,917	71,917
Reg.Liability-Uninsured Property	382,016	757,006	372,193[52]
Total Deductions	$ 1,581,893	$ 1,956,883	$ 1,572,070
RATE BASE	$ 1,420,118	$ 1,041,942	$ 1,411,642

G.1. Utility Plant In Service

Utility Plant In Service represents the gross property, plant and equipment employed by the utility to provide service to customers. The Consumer Advocate computed Utility Plant In Service by starting with the September 30, 2018 plant account balances of $1,819,060 for the utility and the allocated plant of $26,317 from the parent company.[53] Anticipated projects in the amount of $870,530 were added and $91,081 was deducted for projected retirements. The two major assets added were for tank/booster station rehabilitation placed in service in January 2019 for $331,483,

[52] Commissioner Hilliard dissented from the Majority's decision, stating the regulatory liability should have been for the full 757,000 investment. Transcript of Commission Conference, pp. 30-31 (November 4, 2019).
[53] William H. Novak, Pre-filed Direct Testimony, pp. 23-24 (July 12, 2019).

and well/booster station rehabilitation placed in service in June 2019 for $443,126. These rehabilitation projects were necessary to recover the system from damages sustained as a result of the 2016 wildfires.[54] The Company agreed with the Consumer Advocate's projected $2,624,827 Plant in Service for the Attrition Year.[55]

The Hearing Panel found the methodology and outcome used by the Consumer Advocate reasonable and voted unanimously to adopt Plant In Service of $2,624,827 for the Attrition Year.

G.2. Working Capital

Working Capital represents the utility's investment in the cash-on-hand requirement needed to pay its bills timely. For small company rate cases such as this one, working capital requirements are generally computed by taking one-eighth of net cash operating expenses (i.e., expenses that require cash payments to vendors), which equates to a 45-day lag (365/8). Purchased water, however, may be excluded based on the contention that this expense is paid for after associated revenues are received.

The Company computed Working Capital by adding Maintenance Expense, General Expense, and General Taxes forecasted for the Attrition Year and multiplying the total by one-eighth, which results in a Working Capital Allowance of $15,798. The Consumer Advocate calculated Working Capital by adding its forecasted Attrition Year Maintenance Expense, General Expense, Other Operating Expense, and General Taxes and subtracting Purchased Water, and then multiplying the total by one-eighth, which results in a Working Capital Allowance of $12,612.[56]

The Hearing Panel found the Consumer Advocate's methodology to be consistent with sound ratemaking principles. Moreover, the Company's methodology excludes forecasted Other Operating Expense without explanation. With adjustments for forecasts for Maintenance Expense,

[54] J. Bryce Mendenhall, Pre-filed Direct Testimony, pp. 4-5 (February 28, 2019).
[55] Tennessee Water Service's Late Filed Exhibits, Exhibit 6, Schedule 2 (September 10, 2019).
[56] William H. Novak, Pre-filed Direct Testimony, CA Exhibit, Schedule 4.

General Expense, Other Operating Expense, General Taxes and Purchased Water, the Hearing Panel voted unanimously to adopt a Working Capital Allowance of $12,827 for the Attrition Year.

G. 3. Deferred Operating Losses

Because of the devastating wildfires in November 2016 that caused the Company to lose over 90% of its customer base, the Commission in Docket No. 17-00108 authorized the Company to create a regulatory asset account to defer its reasonable operating losses from January 1, 2017 through this rate case proceeding. [57]

The Company sought $245,305 in operating losses through December 2018 which it proposed to recover over a five-year period with an annual amortization of $49,061.[58] The Company further proposed recovery of 2019 losses in a separate surcharge outside of the rate case.[59]

The Consumer Advocate computed the Deferred Operating Loss by starting with the balance in the regulatory asset account of $208,941 as of September 30, 2018. This balance agrees with the Company's response to Commission Staff's data request of August 28, 2019, which appropriately includes the revenue generated from the $7.00 service charge increase authorized by the Commission in Docket No. 17-00108. The Consumer Advocate then selected a ten-year amortization period for recovery of the deferred losses, which results in an annual amortization amount of $20,894 ($208,941/10).[60] It then applied monthly amortization of $1,741 ($208,941/(10*12)) through the Attrition Year to arrive at the midpoint account balance of $198,494 for the Attrition Year. This amount represents the average unrecovered operating losses deferred from January 1, 2017 through September 30, 2018, on which the Company should earn a fair return.

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[57] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, p. 10 (February 21, 2018).
[58] Dante M. DeStefano, Pre-filed Direct Testimony, p. 7 (February 28, 2019).
[59] *Id.* 8.
[60] William H. Novak, Pre-filed Direct Testimony, p. 29 (July 12, 2019).

Further, consistent with the Commission's order in Docket No. 17-00108, the Consumer Advocate recommends the Company be allowed to continue deferring its operational losses for the period October 1, 2018 until the new rates ordered in this proceeding become effective on January 1, 2020.[61] The Company will be allowed recovery of these additional deferred losses in a future rate proceeding. The Company came to agree with the Consumer Advocate's projected $198,494 of deferred losses.[62]

The Hearing Panel found the Consumer Advocate's methodology complied with the Commission's Final Order in Docket No. 17-00108, and adopted a ten-year amortization period for Deferred Operating Losses and voted unanimously to adopt average Deferred Operating Losses of $198,494, as well as annual amortization of $20,894, for the Attrition Year. Additionally, pursuant to the Commission's order in Docket No. 17-00108, the Hearing Panel directed the Company to continue deferring its reasonable operating losses for the period of October 1, 2018 through December 31, 2019 for potential future recovery.

G.4. Deferred Return on Incremental Plant Investment

In Docket No. 17-00108, the Commission authorized the Company to create a regulatory asset to account for the returns on the plant investments required to recover the system from the 2016 wildfires.[63] The order permitted the returns to be computed from the time such new plant was placed in service until this rate case proceeding at the then-authorized rate of return of 6.89%.[64] The primary investments made during this time was the tank/booster station rehabilitation project of $331,483 placed in service in January 2019 and the well/booster station rehabilitation project of

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[61] *Id.*
[62] Tennessee Water Service's Late Filed Exhibits, Exhibit 6, Schedule 2 (September 10, 2019).
[63] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, p. 10 (February 21, 2018).
[64] *Id.*

$443,126 placed in service in May 2019, along with additional, smaller incremental plant additions.[65]

The Consumer Advocate computed the Deferred Return on Incremental Plant Investment by determining actual and forecasted plant additions, depreciation, and plant retirements for the period January 1, 2017 through December 31, 2019, and then applying the annual return of 6.89% to the resulting net plant investments over this period. Using this methodology, the Consumer Advocate calculated deferred returns of $86,486 for the period.[66] The Consumer Advocate then selected a ten-year amortization period for recovery of the deferred returns and then applied monthly amortization of $721 ($86,486/ (10*12)) through the Attrition Year to arrive at the midpoint account balance of $82,162 for the Attrition Year.[67] The Company adopted the Consumer Advocate's projected $82,162 in a late-filed exhibit.[68]

The Hearing Panel found the methodology and calculations of the Consumer Advocate to be accurate and reasonable. Nevertheless, the deferred returns should take into account the Company's admission of liability for failure to properly insure the destroyed assets. The Consumer Advocate did not reduce the deferred returns for any imputed insurance proceeds that may have been collected if the assets were insured. Taking into account the Majority's decision with respect to the finding of a regulatory liability for a lack of sound insurance coverage, the Majority of the Hearing Panel found it appropriate to reduce the deferred returns by imputing $382,016 of putative insurance proceeds to offset the tank/booster and well/booster rehabilitation projects.[69] Using the same methodology as the Consumer Advocate, but for the insurance imputation, the Hearing Panel found deferred returns of $57,574 for the period January 1, 2017 through December 31, 2019. The

[65] J. Bryce Mendenhall, Pre-filed Direct Testimony, pp. 4-5 (February 28, 2019); Dante M. DeStefano, Pre-filed Direct Testimony, Schedule C (February 28, 2019).
[66] William H. Novak, Pre-filed Direct Testimony, p. 32 (July 12, 2019).
[67] *Id.*
[68] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 3 (September 10, 2019).
[69] *See* Section *G.9. Regulatory Liability – Uninsured Property* of this Order; Commissioner Hilliard dissented with the Majority of the Hearing Panel with respect to the insurance related regulatory liability determination.

Hearing Panel voted unanimously to adopt the ten-year amortization period for recovery of the deferred returns and then applied monthly amortization of $480 ($57,574/ (10*12) through the Attrition Year to arrive at the midpoint account balance of $54,695 for the Attrition Year and an annual amortization amount of $5,757 ($480*12).

G.5. Deferred Rate Case Cost

In Docket No. 17-00108, the Commission authorized the Company to defer up to $30,000 of the costs for that case for recovery in this proceeding.[70] The Company filed information showing that the costs for Docket No. 17-00108 were $48,757.[71] The Company further filed information showing forecasted costs of $59,700 for the hearing on the merits in the current docket and $13,488 of costs for the supplemental hearing in this docket.

The Consumer Advocate began with the Test Year balance of $48,757 and adjusted it to the $30,000 cap set by the Commission in Docket No. 17-00108.[72] Projected costs for this docket of $59,700 were added to produce a balance of $89,700. A five-year amortization period was selected and monthly amortization of $1,495 ($89,700/(5*12)) was applied through the Attrition Year to arrive at an average Attrition Year balance of $80,730 for Rate Base and annual amortization of $17,940 ($1,495*12) for expenses.[73] In the original filing, the Company did not project any rate case costs; however, the Company agreed with the Consumer Advocate's projected amount of $80,730 in a late-filed exhibit.[74]

The Hearing Panel found the calculations of the Consumer Advocate to be accurate. Based upon the late-filed exhibit, the Company also agreed with the Consumer Advocate's calculations

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[70] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, p. 10 (February 21, 2018).
[71] *Tennessee Water Service Inc. Response to TPUC Data Request*, DR2, #4 (August 28, 2019).
[72] William H. Novak, Pre-filed Direct Testimony, p. 33-34 (July 12, 2019).
[73] *Id.*
[74] Tennessee Water Service's Late Filed Exhibits, Exhibit 6, Schedule 2 (September 10, 2019).

and five-year amortization period. However, neither the Consumer Advocate nor the Company updated its exhibits to include the $13,488[75] of costs for the supplemental hearing. The Hearing Panel found it appropriate to add these costs to Deferred Rate Case Cost and determined the estimated rate case costs to be $103,188. Applying a five-year amortization period with a monthly amortization of $1,720 ($103,188/(5*12) through the Attrition Year, the Hearing Panel voted unanimously to adopt an average Attrition Year balance of $92,869 for Rate Case Cost and annual amortization of $20,638 ($1,720*12) for expenses.

G.6. Accumulated Depreciation

Accumulated Depreciation recognizes all of the prior depreciation of plant, and this account is netted against gross plant to arrive at the net plant amount on which the Company should earn a fair rate of return. The Consumer Advocate calculated Attrition Year Accumulated Depreciation by using the Test Year balance of $459,597 and adding depreciation expense recognized for the Test Year of $68,410 and subtracting the accumulated depreciation associated with retirements (removal of plant) in the amount of $91,081.[76] In a late-filed exhibit, the Company revised its Accumulated Depreciation amount to agree with the Consumer Advocate in the amount of $436,926.[77]

The Hearing Panel found the calculations accurate and reasonable and voted unanimously to adopt the Consumer Advocate's result of an average Accumulated Depreciation of $436,926 for the Attrition Year.

G.7. Contributions In Aid of Construction

Contributions In Aid of Construction generally represent investments in utility plant that are funded by the utility's customers, developers, or other outside parties. Since the utility's investors did not have any capital outlay associated with these investments, they should not be permitted to

[75] *TWS Supplemental Hearing Costs Filing*, (October 17, 2019).
[76] William H. Novak, Pre-filed Direct Testimony, p. 25 (July 12, 2019).
[77] Tennessee Water Service's Late Filed Exhibits, Exhibit 6, Schedule 2 (September 10, 2019).

earn a return on them. Thus, Contributions In Aid of Construction are deducted from Rate Base to reduce the investment base on which a fair return is computed. Contributions In Aid of Construction are amortized as an offset to depreciation expense over the life of the contributed plant.

The Company and the Consumer Advocate agree that the balance of this account is $633,347.[78] This is based upon the September 2018 account balance of $659,969 with monthly amortization of $1,268 applied for 21 months to arrive at an average balance of $633,347 for the Attrition Year. The Hearing Panel found the calculations accurate and voted unanimously to adopt Contributions In Aid of Construction of $633,347 for the Attrition Year.

G.8. Accumulated Deferred Income Taxes

Accumulated Deferred Income Taxes ("ADIT") recognize that the utility may generally deduct more expenses for tax purposes than for regulatory purposes in the same accounting period, thereby reducing its tax liability in the current year. The most significant portion of ADIT relates to differences in the methods used for computing depreciation expense for tax purposes versus ratemaking purposes. Because these differences cause the utility to pay lower taxes in the current year than the amount of taxes collected from customers through service rates, the benefit of the preferential tax treatment is flowed through to customers by deducting the ADIT from Rate Base in order to offset the returns paid by customers to the investors.

The Consumer Advocate computed ADIT by starting with the Test Year balance for the operating company and the parent in the amount of $54,013.[79] Additions to the deferred account were made by using the midpoint balance of the tax effect on the depreciation timing differences of

[78] *Id.*
[79] *Id.* at 26.

new assets placed in service in the amount of $3,675. In late-filed exhibit, the Company revised its ADIT amount to agree with the Consumer Advocate in the amount of $57,687.[80]

The Hearing Panel found the calculation to be accurate and voted unanimously to adopt ADIT of $57,687 for the Attrition Year.

G.9. Regulatory Liability – Excess Deferred Taxes

The Regulatory Liability for Excess Deferred Taxes represents the amount of excess ADIT that should be returned to ratepayers as a result of the Tax Cuts and Jobs Act. Since the corporate tax rate was reduced from 35% to 21%, the booked amount of ADIT was reduced to recognize that the associated deferred taxes will be paid in the future at the new 21% rate, rather than the higher 35% rate that was in effect when the taxes were originally deferred. The amount of the ADIT reduction, or Excess Deferred Taxes, was collected from customers through rates, but since the higher taxes will never be paid due to the reduction in the corporate tax rate, they must be returned to the ratepayers. Amortization of a regulatory liability is the mechanism used to effectuate the return of Excess Deferred Taxes.

With regard to the amortization of Excess Deferred Taxes, the IRS requires Excess Deferred Taxes related to depreciation timing differences on certain assets to be amortized over the life of the related assets. This category is known as protected Excess Deferred Taxes. Both the Consumer Advocate and the Company agree that protected Excess Deferred Taxes should be amortized over 49 years.[81] The Test Period amount of protected Excess Deferred Taxes of $72,183 was amortized through the Attrition Year at $123 per month ($72,183/(49*12)) to arrive at a midpoint protected Excess Deferred Taxes balance of $69,973 for the Attrition Year.

With regard to unprotected Excess Deferred Taxes, the IRS allows state commissions to choose any amortization period for return of this amount to ratepayers. The Consumer Advocate

[80] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 2 (September 10, 2019).
[81] William H. Novak, Pre-filed Direct Testimony, p. 26 (July 12, 2019);

recommended a three-year amortization period and amortized the Test Period amount of unprotected Excess Deferred Taxes of $3,888 through the Attrition Year at $108 per month ($3,888/(3*12)) to arrive at a midpoint unprotected Excess Deferred Taxes balance of $1,944 for the Attrition Year. Initially, the Company recommended a five-year amortization period for unprotected Excess Deferred Taxes; however, in a late filed exhibit, the Company revised its Regulatory Liability for Excess Deferred Taxes to agree with the Consumer Advocate.[82]

The Hearing Panel found the Consumer Advocate's calculations to be accurate and voted unanimously to adopt a total Regulatory Liability for Excess Deferred Taxes of $71,917 ($69,973 protected plus $1,944 unprotected) and annual amortization of $2,769.

G.10. Regulatory Liability – Uninsured Property

The Consumer Advocate proposed a Regulatory Liability for Uninsured Property of $757,006 based on its contention that some of the assets destroyed by the wildfires should have been fully covered by insurance.[83] According to the Consumer Advocate, had such insurance coverage been properly in place, the Company would have collected sufficient insurance proceeds to replace the destroyed assets, thereby eliminating the need for investor-funded investments for such replacements and, consequently, lowering the Rate Base on which a return is paid by customers.

Thus, the Regulatory Liability for Uninsured Property recommended by the Consumer Advocate essentially removes the rate impact of replacing the destroyed assets. Effectively, the regulatory liability amount proposed here requires the Company to shoulder the full cost of the investments made to recover from the wildfire that the Consumer Advocate contends should have been fully insured. The Consumer Advocate's intent is to completely offset the tank/booster station

[82] Tennessee Water Service's Late-Filed Exhibits, Exhibit 6, Schedule 3 (September 10, 2019).
[83] William H. Novak, Pre-filed Direct Testimony, p. 38 (July 12, 2019).

rehabilitation project costing $331,483 placed in service in January 2019 and a well/booster station rehabilitation project costing $443,126 placed in service in May 2019.[84]

As such, the Consumer Advocate computed a Regulatory Liability for Uninsured Property by taking the cost of the uninsured replacements and amortizing them over 66.67 years (1.5% amortization rate) which is the same as the economically useful life of the assets recognized in the Plant In Service and related Depreciation calculations.[85] Using this methodology, the Consumer Advocate computed accumulated amortization of the regulatory liability through the Attrition Year to arrive at the midpoint balance of $14,175 of accumulated amortization and annual amortization expense of $11,619. The Consumer Advocate also determined the ADIT related to the uninsured assets by computing the tax effect on the deprecation timing differences of uninsured assets through the midpoint of the Attrition Year to arrive at an incremental ADIT balance of $3,426. Based on these calculations, the Consumer Advocate computed and recommended a Regulatory Liability for Uninsured Property of $757,006 ($331,483 + $443,126 - $14,175 - $3,428).

Here, the Company admitted that some of the destroyed property was under-insured and that a Regulatory Liability is appropriate to recognize the Company's failure to properly insure the plant.[86] Thus, the issue is not whether the Company was imprudent. With the Company's admission, the issue for the Hearing Panel is the extent to which its failure should be recognized in new rates. The Company contends that, based upon a proxy project completed in nearby Sugar Mountain, North Carolina immediately prior to the November 2016 wildfires, the Company should have insured the destroyed plant for $432,016.[87] The Company asserts this level of insurance coverage would have been reasonable because it is based upon the actions the Company should

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[84] *Id.*
[85] *Id.*
[86] Transcript of Hearing, pp. 40-41, 50 (September 9, 2019); Transcript of Commission Conference, p. 70 (October 14, 2019).
[87] J. Bryce Mendenhall, Pre-filed Rebuttal Testimony, pp. 6-7 (August 16, 2019).

have taken in 2016 to insure the property in light of the information available to the Company at that time.[88] As the insurance policy the Company has in place for other assets contains a $50,000 casualty loss deductible, the Company asserts that a Regulatory Liability for Uninsured Property of $382,016 should be recognized ($432,016 - $50,000).[89]

The Consumer Advocate, however, argues the Company's assumptions and computations are too speculative and hypothetical to be used for ratemaking purposes. The Consumer Advocate maintains the Sugar Mountain proxy project is a diversionary and unsupported assertion and not comparable to the Company's Chalet Village projects at issue in this docket and, therefore, should be rejected.[90] The Company maintains that it would be unreasonable to use hindsight to hold it accountable for the unforeseen circumstances of the wildfires that devastated the system.[91]

In response to the destruction of the wildfires, the Company invested $757,006 to re-establish water service to replace assets it concedes were not properly insured. The Company has taken responsibility for the lack of insurance and has agreed to absorb half of those costs to replace the property damaged by the wildfires.[92] The Company maintains its proposition is not an arbitrary splitting of the baby, but rather based on several arguments, including the use of a proxy as a basis of insurance coverage it should have had.

Company witness Bryce Mendenhall testified that the Sugar Mountain project should have been used by the Company at that time to determine an appropriate replacement cost for insurance coverage of the destroyed assets. In support of the Sugar Mountain proxy, the Company asserted the geography, common materials, labor, and other costs such as engineering and design relatively comparable between the Sugar Mountain and Chalet Village booster station projects.[93] Mr.

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[88] J. Bryce Mendenhall, Supplemental Rebuttal Testimony, pp. 3-4 (October 9, 2019).
[89] J. Bryce Mendenhall, Rebuttal Testimony, p. 7 (August 16, 2019).
[90] William H. Novak, Pre-filed Second Supplemental Testimony, p. 6-7 (October 7, 2019).
[91] Transcript of Hearing, p. 53 (September 9, 2019).
[92] *Id.*
[93] *Id.* at 167-169.

Mendenhall also testified that disasters, such as the wildfires, can create a premium on reconstruction of damaged assets due to supply and demand pressure on contract labor and materials and that the Company received only one qualified bid to complete the rehabilitation projects at Chalet Village.[94] The Company reported that only one bid was received for the replacement of the booster station and only one bid was received for the Clubhouse project from a bidder with qualifications and certification.[95]

A basic tenet of just and reasonable rates requires a utility to have the opportunity to earn a reasonable rate of return for investments for used and useful plant.[96] Rates should be fair to both the ratepayer and the utility. On one hand, the Consumer Advocate frames this matter as a near zero-sum proposition in which the full cost of the replacements should be removed from rate base as a result of the Company's imprudence. However, the Majority of the panel found that requiring the Company to forgo 100% of its investment through the application of hindsight three years after the wildfires and the rebuilding of assets destroyed in the fire would be punitive and unreasonable.

Based on the evidentiary record before it, a Majority of the Hearing Panel found the regulatory liability amount proposed by the Company to be reasonable.[97] This result requires the Company to forgo 49.3% of the total cost of replacement while providing the customers with the benefit of replacement assets that will have a longer service life. One must consider the age of the plant that was replaced and the circumstances in which it was replaced. The destroyed well and tank booster stations were existing when the Company acquired the utility and was granted its certificate of convenience and necessity ("CCN") in 1984, making the plant more than 30 years old at the time

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[94] J. Bryce Mendenhall, Pre-filed Rebuttal Testimony, p. 6 (August 16, 2019).
[95] *Id.*
[96] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 692-693 (1923).
[97] Commissioner Herbert H. Hilliard dissented from the Majority- Transcript of Commission Conference, pp. 30-31 (November 4, 2019): "Commissioner Hilliard: I voted no primarily because I think the company should have had to put aside $700,000. I thought their explanation for why they were not adequately insure the facilities was inadequate. I also thought it was very negligent not to insure something at a bare premium where the deductible was higher than what you'd actually get paid if you actually had a loss."

of the 2016 wildfires. The tank and well booster stations have been completely replaced with new plant that will undoubtedly serve the customers far longer than the destroyed plant would have. Moreover, it is reasonable to assume that routine maintenance and repair costs will decline in the foreseeable future due to the replacement of the aging assets with new plant. Customers therefore will likely receive the benefits of longer service life and reduced costs due to the installation of the new plant.

Further, the Commission does not by rule or order specifically require utilities to fully insure against all possible casualty losses or otherwise endorse specific insurance coverage parameters, although insurance coverage or the reasonableness of a policy is certainly a consideration for the Commission. A public utility does not have license to conduct its affairs recklessly. Nevertheless, the Commission has authorized recovery of nonrecurring, extraordinary costs from ratepayers for uninsured casualty losses that were beyond the utility's control. For instance, in Docket Nos. 08-00201, 12-00051, and 13-00121, the Commission authorized the creation of regulatory assets for recovery of storm-damage costs from ratepayers incurred as a result of devastating winter storms.[98] And in Docket No. 11-00180 the Commission authorized Berry's Chapel Utility, Inc. to create a regulatory asset for recovery of specific flood-damage costs from ratepayers incurred as a result of catastrophic flooding that occurred in Middle Tennessee in May 2010.[99] The wildfires in 2016 certainly qualify as an extraordinary event beyond the control of a public utility. Thus, it is consistent with the Commission's prior ratemaking decisions and policy to permit the Company to

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[98] *See In Re: Entergy Arkansas, Inc's Proposed Storm Damage Rider*, Docket No. 08-00201, *Order Approving Storm Damage Rider*, (February 2, 2009); *In Re: Petition of Kingsport Power Company D/B/A AEP Appalachian Power to Implement a Storm Damage Rider Tariff for Recovery of Storm Costs*, Docket No. 12-00051, *Order Approving Proposed Tariff*, p. 4 (November 28, 2012); *In Re: Petition of Kingsport Power Company D/B/A AEP Appalachian Power fro Approval of Deferred Accounting*, Docket No. 13-00121, *Order Approving Request to Defer Storm Cost,* p.2 (October 16, 2014).

[99] *See In Re: Petition of Berry's Chapel Utility, Inc. to Recover Costs to Repair Flood Damage and to Refund Customer Service Fees*, Docket No. 11-00180, *Final Order*, pp. 15-17, (August 21, 2012).

recover the uninsured casualty losses sustained in this case which were undoubtedly extraordinary and beyond the utility's control.

Finally, allowing the Company recovery of costs related to restoring the water system from the fire damage is consistent with the Commission's previous order on this issue in Docket No. 17-00108. In that docket, the Commission authorized the Company to establish a regulatory asset to accrue and defer the returns on the capital projects necessary to repair the fire damage and restore the system to operational status. Those capital projects have been identified in this proceeding as the tank and well booster station rehabilitation projects. And by entering the rate order in Docket No. 17-00108, the Commission determined that probable future recovery of the capital costs related to these projects was proper and in accordance with the ratemaking and regulatory accounting principles established by the Commission's Uniform System of Accounts.

Based on the foregoing, the Majority of the Hearing Panel authorized a Regulatory Liability for Uninsured Property by taking the proposed amount of $382,016 amortized over 66.67 years (1.5% amortization rate) through the Attrition Year to arrive at the midpoint balance of $8,041 of accumulated amortization and annual amortization expense of $5,730 ($382,016 * 1.5%). The ADIT related to the underlying property was determined by computing the tax effect on the deprecation timing differences through the midpoint of the Attrition Year to arrive at an incremental ADIT balance of $1,782. Based on these calculations, the Majority of the Hearing Panel voted to authorize a Regulatory Liability for Uninsured Property of $372,193 ($382,016 - $8,041 - $1,782).

H. REVENUE CONVERSION FACTOR

The Revenue Conversion Factor represents the multiple figure needed to convert the operating revenue deficiency to the revenues necessary to the produce that income. Specifically, taxes and other fees must be collected on top of the revenue in order for the necessary amount of revenues to be collected by the Company to cover its revenue deficiency. As stated by the

Consumer Advocate, the Commission traditionally includes the forfeited discount in its revenue conversion factor and the Company offers no explanation for its exclusion.[100] The Advocate further states that the Commission has also traditionally treated the inspection fee as a prepaid tax instead of including it as a component of the revenue conversion factor.

The Hearing Panel voted unanimously to adopt a forfeited discount factor of 0.014773, an uncollectible ratio of 0.002452, a state excise tax rate of 6.5% and a federal income tax rate of 21% which yields a recommended revenue conversion factor of 1.337392.

I. RATE OF RETURN AND COST OF CAPITAL

The goal of regulatory rate setting is to ensure a fair rate of return on a company's investments while ensuring the safety and reliability of the service provided. The fair rate of return standard descends from court decisions in the *Hope* and *Bluefield* cases.[101] A fair rate of return is achieved when (1) the return is comparable to other businesses that bear similar risks; (2) the allowed return is sufficient to ensure financial integrity; and (3) the company can attract, at reasonable cost, credit to meet its capital requirements.

The Company proposes a capital structure that is a 50%/50% split of long-term debt and equity. The Company notes that this capital structure is consistent with the recent history of TWS's parent, Utilities, Inc. ("UI"). TWS is a wholly-owned subsidiary of UI.[102] The Company proposes a cost of equity of 10.50%. The Company and its parent company are not publicly traded. The Company estimates the cost equity for use in the proceeding using an ensemble of the discounted cash flow and capital asset pricing models applied to a comparison group of natural gas and water

[100] William H. Novak, Pre-filed Direct Testimony, p. 42 (July 12, 2019).
[101] *Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia*, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).
[102] Dante M. DeStefano, Pre-filed Direct Testimony, p. 10 (February 29, 2019).

utilities.[103] The Company proposes a cost of debt of 5.04%. [104] The resulting overall rate of return based upon the Company's capital structure, debt cost, and equity return is 7.77%.[105]

The Consumer Advocate notes that, for this case, it "has no objection to the Cost of Capital proposed by the Company that produces an overall return of 7.7%."[106] Based upon the positions taken by the parties, there is no controversy concerning the overall cost of capital of 7.77%. At the Hearing, Consumer Advocate witness Novak stated that "It's my understanding that the company and the Consumer Advocate had agreed to the cost of capital prior to the company's filing" and "we are not contesting the company's cost of capital."[107]

The Company proposes a capital structure that is a 50%/50% split of long-term debt and equity. Similarly, in an order issued February 21, 2019, the North Carolina Utilities Commission established a capital structure of 50.91% equity and 49.09% long-term debt for an affiliate of TWS.[108] As such, the panel found the proposed capital structure of a 50%/50% split of long-term debt and equity is reasonable for use in this proceeding. Similarly, the North Carolina Commission set the cost of debt to be 5.68%. The panel also found the proposed debt cost in this proceeding of 5.04% is comparable and thus, reasonable.

The Hearing Panel voted unanimously to adopt the 7.77% overall rate of return and the 10.5% equity return. The related Interest Expense is calculated by applying the adopted weighted cost of debt to the adopted rate base amount. Using the adopted rate base of $1,411,642 and weighted cost of debt of 2.52%, Interest Expense for the Attrition Year is $35,573, the Hearing Panel voted unanimously to adopt Interest Expense for the Attrition Year of $35,573.

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[103] Jared Deason, Pre-filed Direct Testimony, p. 23 (February 29, 2019).
[104] Dante M. DeStefano, Pre-filed Direct Testimony, p. 10 (February 29, 2019).
[105] *Id.*
[106] William H. Novak, Pre-filed Direct Testimony, p. 40 (July 12, 2019).
[107] Transcript of Hearing. p. 195 (September 9, 2019)
[108] Tennessee Water Service Inc's Responses to First Informal Discovery Request of the Consumer Advocate Unit Item 6 (April 10, 2019).

J. REVENUE DEFICIENCY

Based upon the foregoing, the Majority of the Hearing Panel found that the Company will experience a Revenue Deficiency of $111,020 for the Attrition Year ending December 31, 2020, at presently-authorized service rates. Thus, new rates should be designed and implemented which will generate additional annual water service revenues of $111,020. This increase in revenues will afford the Company a reasonable opportunity to earn its recommended fair rate of return of 7.77%.

K. RATE DESIGN AND OTHER TARIFF CHANGES

Rate design covers the manner in which new rates reflecting the revenue deficiency are recovered from customers. This section also includes changes to the tariff, or terms and conditions of service.

K.1. Rate Design

The Company proposed to phase in rates over a three-year period in order to avoid rate shock, but it should be noted that TWS requested $300,444 in additional revenues – an amount that exceeds the Majority Panel's revenue deficiency of $111,020. TWS is also proposed new rates for private fire service. The Company's proposed rate design was as follows:

	Current	Year 1	Year 2	Year 3
Monthly Flat Rate (Includes 2,000 gallons)	$25.70	$50.00	$74.00	$94.00
Per Gallon Charge (Over 2,000 Minimum)	$13.30	$16.50	$19.00	$20.65
Private Fire Service				
Multi-Use Line	$ 0.00	$11.33	$24.00	$35.80
Fire Only Line	$ 0.00	$22.67	$48.00	$71.60

Based upon the Company's recommended rate design, which includes a lower monthly average water usage level, the average monthly water bill would be approximately $125 prior to sales tax.

The Consumer Advocate calculates a revenue deficiency of $73,087, and the following rates without a phase in:[109]

	Current	Proposed
Monthly Flat Rate (Includes 1,000 gallons)	$25.70	$33.39
Per Gallon Charge (Over 1,000 Minimum)	$13.30	$17.28

While the Consumer Advocate does not oppose the implementation of private fire service, it does not believe that TWS has identified a significant need for the tariff and has not presented justification to support the proposed rates.[110] Based upon the Consumer Advocate's recommended rate design, the average monthly water bill would be approximately $87 prior to sales tax.

The goal of overall rate design is to establish a system of rates that will enable a utility to generate sufficient revenues to cover expenses needed to operate the utility, plus an equity return for investors. There are often, however, many factors that are taken into consideration when designing rates, including those related to economics and social considerations. For example, a social consideration may be to establish rates for residential customers that are affordable but not necessarily reflective of the actual cost of service. Thus, in some cases, rates for certain services or classes of services (i.e., industrial and large commercial) may be priced further above cost in order to maintain residential services at affordable rates. In this case, however, TWS serves only residential customers so the revenue deficiency must be recovered solely from residences.

As concluded herein the Majority of the Hearing Panel calculated an annual revenue deficiency of $111,020 which is based upon forecasted attrition period revenues, expenses, applicable taxes, and a rate base with a fair return. Many factors go into these calculations and especially important to rate design is forecasted attrition period number of customers and average

[109] William H. Novak, Pre-filed Direct Testimony, p. 45-46 (July 12, 2019).
[110] William H. Novak, Pre-filed Supplemental Testimony, pp. 4-5 (July 31, 2019).

customer water usage. Since revenue calculations are based upon 3,732 annual customer bills with an average monthly usage number 4,080 gallons, it is appropriate to also use these amounts in order develop a rate design that will recover the necessary annual revenue deficiency.

Here, there are primarily two rate components: (1) an existing flat monthly rate of $25.70 which includes a set amount of usage [currently it includes the initial 1,000 gallons of usage] and (2) an existing $13.30 charge for each additional 1,000 gallons used above the minimum. Since rates were established in the emergency petition in Docket No. 17-00108, however, the Company has incorrectly applied its tariff by including 2,000 gallons in the minimum monthly flat rate and charging usage rates in excess of 2,000 gallons used monthly.[111] This is most unfortunate as it may cause much confusion for ratepayers when rates are changed.

The Hearing Panel found that the Company's proposed private fire service offerings are reasonable and also recommends approval of the proposed rates which are expected to generate additional revenues of $1,289 annually, leaving the remaining $109,731 revenue deficiency to be collected from the monthly flat rate and water usage component. Based upon this remaining revenue deficiency, the Hearing Panel voted unanimously to adopt a Monthly flat rate of $50.00 for the first 1,000 gallons of water used. Any additional water used beyond the first 1,000 gallons is subject to a volumetric charge of $14.95 per 1,000 gallons. A comparison between the prior rates and the new rates is below.

	Current	**Commission**
Monthly Flat Rate (Includes 1,000 gallons)	**$25.70**	**$50.00**
Per Gallon Charge (Each additional 1,000 gallons)	**$13.30**	**$14.95**

In this case, the Consumer Advocate used average water usage based upon the three years preceding the wildfire to compute rates. The rationale is that current volumes may not be as reliable

[111] William H. Novak, Pre-filed Direct Testimony, p. 12 (July 12, 2019).

due to a number of factors. Illustrative of this fact is that the Company's most recent two years of water usage indicates a water loss percentage of 30.43% for the twelve months ending September 30, 2017 and 71.52% for the ending September 30, 2018. The historical water loss percentage for the three years prior to the wildfires averaged only 14%. Moreover, the Company's recent volumes could be impacted by water used in company testing and maintenance of facilities, construction clean-up and possibly other factors such as the size of new homes, newer construction efficiencies and water conservation efforts of consumers. Due to these uncertainties, the rate design adopted by the Hearing Panel increases the Company's fixed revenue recovery to approximately 52% of total revenues, thereby minimizing the revenue impacts of potentially inaccurate water usage levels and high water loss percentages. In this manner, the Company's revenues are more likely to remain stable, and thus more predictable, by recovering more fixed costs through fixed charges, as opposed to relying on the recovery of fixed charges through revenue streams collected via volumetric usage charges. Based upon the proposed customer levels and average water usage, the average water bill will be approximately $96 monthly.

K.2. Operational Cost Pass Through Mechanism

In Docket No. 17-00108, the Commission implemented an Interim Emergency Operational Cost Pass Through Mechanism ("OCPTM") as proposed by TWS and modified by the Consumer Advocate.[112] This mechanism authorized TWS to pass through to customers nondiscretionary increases or decreases in costs incurred for purchased water and purchased electricity such that if the price of purchased water or electricity increased or decreased, the Company could adjust customer rates accordingly. In fact, the tariff required TWS to make semi-annual filings with the

[112] *In re: Petition of Tennessee Water Service, Inc. for Approval of an Interim Emergency Wildfire Restoration Surcharge, Interim Emergency Water Service Availability Surcharge, Interim Emergency Make-Whole Surcharge, and an Interim Emergency Operation Cost Pass-Through Mechanism*, Docket No. 17-00108, *Final Order*, p. 11 (February 21, 2018).

Commission to adjust customer rates for changes in these expenses; however the Company never made the requisite filings to utilize the mechanism.

In the instant docket, TWS wants to make the mechanism permanent because it argues the overall rate proposal does not include a method to recover increases in production costs. Additionally, the Company contends the OCPTM will provide benefits beyond the attrition year where variable costs will inevitably rise.[113] The Consumer Advocate reasons that the mechanism be terminated because it is recommending that the Company be allowed to continue deferring operating losses through December 31, 2019.[114] The Consumer Advocate argues this deferment makes the continuation of the mechanism no longer necessary.

The panel found that the uncertainty in water usage levels as discussed above makes it difficult to calculate an accurate amount of purchased water. Additionally, this uncertainty makes it difficult to establish a baseline for the amount of electricity needed to pump the water. Moreover, the panel further found that the Company's overall operations during the near future could be quite volatile (not just purchased water and electricity) due the number of customers added, changes in water usage, and efficiencies experienced with a more efficient water system. Thus, it is quite likely that a review of rates will be necessary in the next two years once these variables are better known. Accordingly, the Hearing Panel voted unanimously to terminate this mechanism until such time that the Company's operations are more stable so a sound baseline can be established on which to compare future changes.

K.3. Qualified Infrastructure Improvement Program

The Company proposed a Qualified Infrastructure Improvement Program ("QIIP") mechanism to be implemented in order for the Company to recover its qualifying incremental non-revenue producing plant infrastructure investment relating to:

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[113] Dante M. DeStefano, Pre-filed Direct Testimony, pp. 6-7 (August 16, 2019).
[114] William H. Novak, Pre-filed Rebuttal Testimony, pp. 43-44 (July 12, 2019).

> *Distribution Infrastructure* – a Replacement distribution and transmission mains and valves installed as replacements for existing facilities, reinforcement of existing facilities or otherwise ensuring reliability of existing facilities; Hydrants, Services, Meters and Meter Installations – installed as in-kind replacements, reinforcements or ensuring reliability of existing facilities; Unreimbursed funds related to capital projects to relocate facilities required by government highway projects; Capitalized tank repairs and maintenance that serve to replace, reinforce, otherwise ensure reliability of existing facilities.
>
> *Production and Pumping Infrastructure* – Replacement of water treatment facilities and equipment installed as replacements for existing facilities, reinforcements of existing facilities or otherwise ensuring reliability of existing facilities; Raw Water and Finished Water pumping equipment and structures installed as replacements, reinforcements or otherwise reliability of existing facilities.[115]

In essence the Company would provide a forecast of QIIP investment and begin collecting appropriate carrying charges via a customer surcharge. At year end, TWS would true-up the budget to actual investment along with a true-up over/under collections from consumers. The Consumer Advocate offered no opinion on this mechanism.

The Hearing Panel found the QIIP was not in the public interest at this time and voted unanimously that the request be denied. The main emphasis has been and should continue to be for TWS to build facilities necessary to service customers. Within the QIIP, the Company plans to establish more reliable facilities and improve them. While added reliability is important, the emphasis has to be to provide basic service that is reasonably affordable. In light of the major rate increases that customers are about to realize, adding infrastructure that is not absolutely necessary to actually serve customers at this time could very well make rates unaffordable and unreasonable.

However, the Hearing Panel noted that if a project becomes necessary to furnish service, and absent repairing or replacing the infrastructure would result in inadequate or loss of service, the Company may petition for emergency relief in the form of additional deferred accounting and present its case. Moreover, if a local government entity requires the utility to replace, move or otherwise cause the Company to spend money on capital projects, the Company has the option to

[115] Dante M. DeStafano, Pre-filed Direct Testimony, Exhibit 7, Original Sheet No. 19 (February 28, 2019).

file an emergency petition for necessary relief. Finally, the Company's earnings volatility in the near future will make it quite likely that an overall review of rates will be necessary in the next two years.

K.4. Other Miscellaneous Tariff Changes

In addition to the aforementioned tariff provisions relating to the private fire service, OCPTM, and the QIIP, TWS provides several other miscellaneous tariff changes in its tariff.

In addition to requiring a third party to pay the new 21% tax rate on all Contribution-in-aid of Construction ("CIAC"), TWS proposes to also collect the 6.5% Tennessee state excise tax rate on CIAC. The Consumer Advocate, however, correctly points out the Tennessee state excise tax does not apply to CIAC.[116] Moreover, the Commission decided this very topic in its order issued on October 1, 2018, in Docket 18-00001, *Order Approving Staff Report and Recommendation.* [117] Within that order, the Commission ordered all small water and wastewater utilities to file a tariff with a CIAC gross up factor of 26.58%, which excludes excise tax. TWS, however, failed to submit the required tariff. The Consumer Advocate had no objection to the remaining miscellaneous changes to TWS's tariff.[118]

The Hearing Panel directed TWS to file a tariff for CIAC reflecting a 26.58% gross up factor and to file the specific tariff language attached to the October 1, 2018 order issued in Docket No. 18-00001 and voted unanimously to approve the remaining miscellaneous tariff changes.

IT IS THEREFORE ORDERED THAT:

1. The rates filed by Tennessee Water Service, Inc. on February 28, 2019 are denied;

[116] William H. Novak, Pre-field Supplemental Testimony, p. 2 (July 31, 2019).
[117] *In Re: Tennessee Public Utility Commission Investigation of Impacts of Federal Tax Reform on the Public Utility Revenue Requirements*, Docket No. 18-00001, *Order Approving Staff Report and Recommendations*, pp. 3-4.
[118] William H. Novak, Pre-filed Supplemental Testimony, pp. 4-5 (July 31, 2019).

2. For purposes of the rates herein, the attrition period Revenues for the twelve months ending December 31, 2020, are $248,782 in Water Sales and $4,919 in other Revenues, and a forfeited discount rate of 1.4773%;

3. For purposes of the rates herein, the Operations and Maintenance Expenses for the attrition period are $141,466.

4. For purposes of the rates herein, Depreciation Expense for the attrition period is $42,735; (2) Amortization of Contributions in Aid of Construction of $15,213; and (3) Amortization of Investment Tax Credit of $48.

5. The (1) Amortization of Regulatory Liability for Excess Deferred Taxes of $2,769, with a 49-year amortization period for Protected Excess Deferred Taxes and a three-year amortization period for Unprotected Excess Deferred Taxes; and (2) Amortization of Regulatory Liability for Uninsured Property of $5,730, with a 66.67-year amortization period consistent with the associated uninsured plant.

6. The (1) a ten-year amortization period for Deferred Operating Loss with an annual amortization of $20,894; (2) a ten-year amortization period for Deferred Return on Incremental Plant Investment with an annual amortization of $5,757; and (3) a five-year amortization period for Deferred Rate Case Expense with an annual amortization of $20,638. The Company is authorized to continue deferring its reasonable operating losses as agreed to by the parties through December 31, 2019, for potential future recovery.

7. For purposes of the rates herein, the Net State Excise Tax is calculated using the statutory rate of 6.5% and Federal Income Taxes are calculated using the 21% statutory rate for the for the attrition period. Other Taxes for the attrition period are approved as follows: Payroll Tax of $1,940, Franchise Tax of $1,122, Gross Receipts Tax of $144, Property Tax of $18,188; and Inspection Fees of $1,054.

8. For purposes of the rates herein, Rate Base is $1,411,642 for the attrition period;

9. For purposes of the rates herein, the Net Operating Income is $26,672 for the attrition period based on current rates prior to application of taxes for additional attrition period revenues;

10. For purposes of the rates herein, the overall Revenue Conversion Factor of 1.337392 based upon a forfeited discount factor of 0.014773, an uncollectible ratio of 0.002452, a state excise tax rate of 6.5% and a federal income tax rate of 21%.

11. For purposes of the rates herein, the capital structure is composed of 50.00% debt and 50.00% equity; debt cost of 5.04% and an equity return of 10.50% with an overall rate of return of 7.77%;

12. For purposes of the rates herein, using the adopted Rate Base of $1,411,642 and weighted cost of debt of 2.52%, Interest Expense is calculated in the amount of $36,573 for the attrition period.

13. For purposes of the rates herein, the Revenue Deficiency of $111,020 is established for the attrition period.

14. The Monthly Flat Rate for the first 1,000 gallons of water usage shall be increased from $25.70 to $50.00 per month.

15. The volumetric charge for each 1,000 gallons above the first 1,000 gallon water usage shall be increased from $13.30 to $14.95 per 1,000 gallons.

16. The proposed Private Fire Service rates of $35.80 for multi-use lines and $71.60 for Fire-Only lines are approved.

17. The existing Interim Emergency Operational Cost Pass Through Mechanism is terminated.

18. The proposed Qualified Infrastructure Improvement Program surcharge is denied as it is not in the public interest at this time.

19. Tennessee Water Service Inc. is to file a tariff regarding Contributions in Aid of Construction to reflect a 26.58% gross up factor, and to file the specific tariff language attached to the October 1, 2018 order issued in Commission Docket No. 18-00001.

20. The rates approved herein shall become effective January 1, 2020.

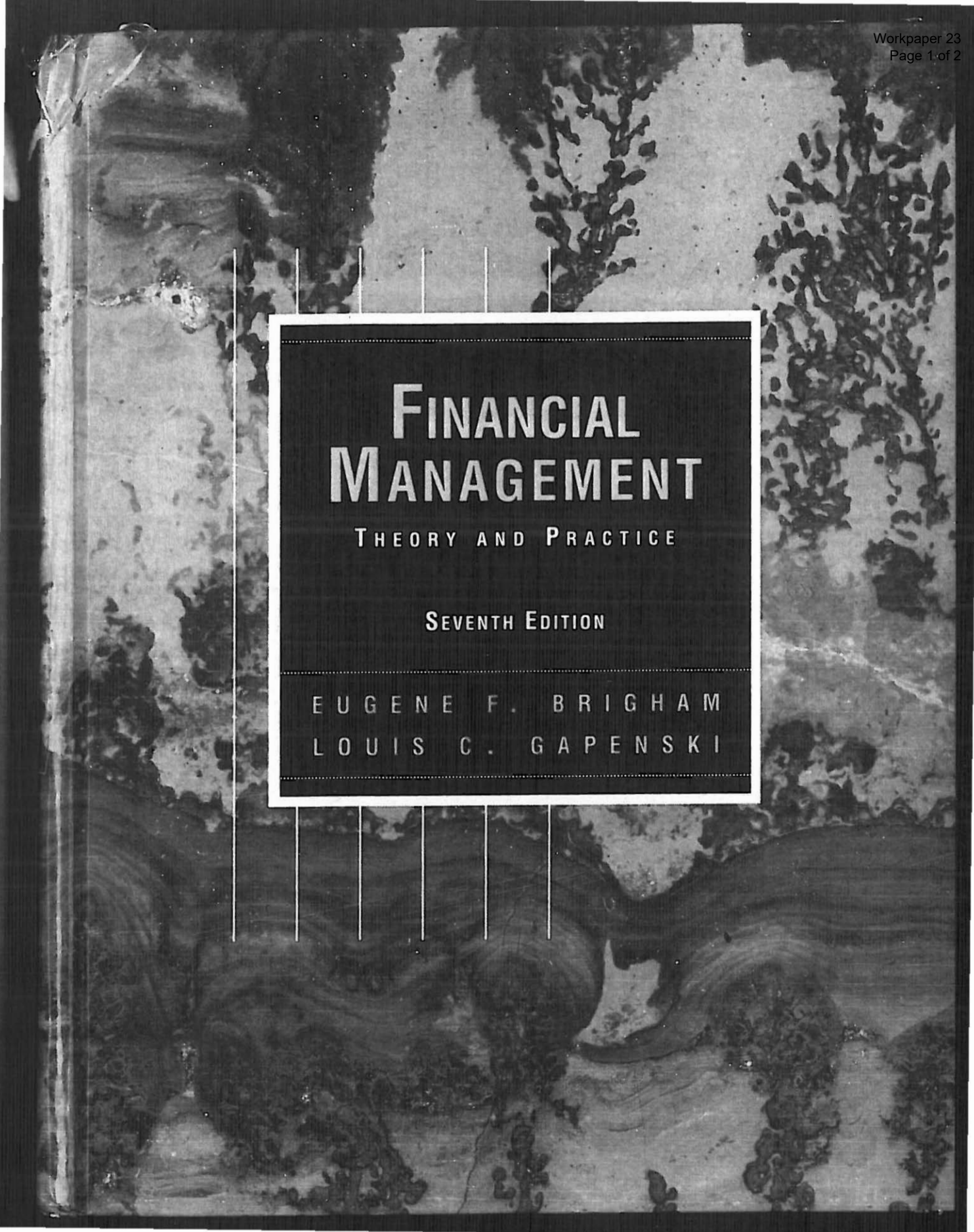
21. Any person who is aggrieved by the Commission's decision in this matter may file a Petition for Reconsideration with the Commission within fifteen days from the date of this Order; and

22. Any person who is aggrieved by the Commission's decision in this matter has the right to judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty days from the date of this Order.

Chair Robin L. Morrison and Commissioner David F. Jones concur. Commissioner Herbert H. Hilliard dissents in part where noted herein.

ATTEST:

Earl R. Taylor, Executive Director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Workpaper 23
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by interest payments; preferred stockholders are compensated by fixed dividend payments; and the firm's remaining income belongs to its common stockholders and serves to "pay the rent" on stockholders' capital. Management may either pay out earnings in the form of dividends or retain earnings for reinvestment in the business. If part of the earnings is retained, an *opportunity cost* is incurred: Stockholders could have received those earnings as dividends and then invested that money in stocks, bonds, real estate, and so on. *Thus, the firm should earn on its retained earnings at least as much as its stockholders themselves could earn on alternative investments of equivalent risk.*

What rate of return can stockholders expect to earn on other investments of equivalent risk? The answer is k_s, because they can earn that return simply by buying the stock of the firm in question or that of a similar firm. Therefore, if our firm cannot invest retained earnings and earn at least k_s, then it should pay those earnings to its stockholders so that they can invest the money themselves in assets that do provide a return of k_s.

Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate k_s. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive—no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.

SELF-TEST QUESTIONS

What are the two types of common equity whose costs must be estimated? Explain why there is a cost for retained earnings.

THE CAPM APPROACH

As we saw in Chapter 5, the Capital Asset Pricing Model is based on some unrealistic assumptions, and it cannot be empirically verified. Still, because of its logical appeal, the CAPM is often used in the cost of capital estimation process.

Under the CAPM we assume that the cost of equity is equal to the risk-free rate plus a risk premium that is based on the stock's beta coefficient and the market risk premium as set forth in the Security Market Line (SML) equation:

$$k_s = \text{Risk-free rate} + \text{Risk premium}$$
$$= k_{RF} + (k_M - k_{RF})b_i.$$

Given estimates of (1) the risk-free rate, k_{RF}, (2) the firm's beta, b_i, and (3) the required rate of return on the market, k_M, we can estimate the required rate of

VALUATION

MEASURING AND MANAGING THE VALUE OF COMPANIES

THIRD EDITION

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$$k_p = \frac{\text{div}}{P}$$

where k_p = The cost of preferred stock
div = The promised dividend on the preferred stock
P = The market price of the preferred stock

If the current market price is not available, use yields on similar-quality issues as an estimate. For a fixed-life or callable preferred stock issue, estimate the opportunity cost by using the same approach as for a comparable debt instrument. In other words, estimate the yield that equates the expected stream of payments with the market value. For convertible preferred issues, option-pricing approaches are necessary.

STEP 3: ESTIMATE THE COST OF EQUITY FINANCING

The opportunity cost of equity financing is the most difficult to estimate because we can't directly observe it in the market. We recommend using the capital asset pricing model (CAPM) or the arbitrage pricing model (APM). Both approaches have problems associated with their application, including measurement difficulty. Many other approaches to estimating the cost of equity are conceptually flawed. The dividend yield model (defined as the dividend per share divided by the stock price) and the earnings-to-price ratio model substantially understate the cost of equity by ignoring expected growth.

The Capital Asset Pricing Model

The CAPM is discussed at length in all modern finance texts (for example, see Brealey and Myers, 1999, or Copeland and Weston, 1992).[6] These detailed discussions will not be reproduced here. (In this section, we assume that you are generally familiar with the principles that underlie the approach.) The CAPM postulates that the opportunity cost of equity is equal to the return on risk-free securities plus the company's systematic risk (beta) multiplied by the market price of risk (market risk premium). The equation for the cost of equity (k_s) is as follows:

[6] T. Copeland and J. Weston, *Financial Theory and Corporate Policy*, 3rd ed. (Reading, MA: Addison-Wesley, 1992); and R. Brealey and S. Myers, *Principles of Corporate Finance*, 5th ed. (New York: McGraw-Hill, 1999).

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-5, SUB 565

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of	)	ORDER APPROVING RATE
North Carolina, Inc. for a General Increase	)	INCREASE AND INTEGRITY
in its Rates and Charges	)	MANAGEMENT TRACKER

HEARD: Gaston County Courthouse, Gastonia, North Carolina, on August 23, 2016; Buncombe County Courthouse, Asheville, North Carolina, on August 24, 2016; Government Center, Statesville, North Carolina, on August 25, 2016; and Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina, on August 29 and 30, 2016

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

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B. Craig Collins, Associate General Counsel, SCANA Corporation, MC C222, 220 Operation Way, Cayce, South Carolina 29033-3701

For the Using and Consuming Public:

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Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For Blue Ridge Paper Products, Inc., d/b/a Evergreen Packaging:

Adam Olls and Jeffrey D. McKinney, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, NC 27601

BY THE COMMISSION: On February 17, 2016, Public Service Company of North Carolina, Inc. (PSNC or the Company), filed its Letter of Intent to File for authority to adjust and increase its retail natural gas rates and charges pursuant to Commission Rule R1-17(a).

On March 3, 2016, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, which was granted by the Commission on March 7, 2016.

On March 31, 2016, PSNC filed an Application for a General Rate Increase (Application) seeking a general increase in and revisions to its rates and charges, implementation of a new Integrity Management Tracker mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, and proposed funding for gas distribution research activities conducted by the Gas Technology Institute. Included with its Application was information and data required by NCUC Form G-1, pursuant to Commission Rule R1-17(b)(12). In addition, the Application was supported by the direct testimony and exhibits of Company witnesses: D. Russell Harris, President and Chief Operating Officer of PSNC and President of Gas Operations for South Carolina Electric & Gas Company (SCE&G); Jimmy E. Addison, Executive Vice President and Chief Financial Officer of PSNC, SCANA Corporation, and the other subsidiaries of SCANA; George B. Ratchford, Vice President – Gas Operations for PSNC; Sharon D. Boone, Business Unit Controller of PSNC; James A. Spaulding, Financial Accounting Manager for PSNC; Candace A. Paton, Rates & Regulatory Manager for PSNC; Rose M. Jackson, General Manager – Supply & Asset Management for SCANA Services, Inc.; Robert B. Hevert, Partner of ScottMadden, Inc.; and John J. Spanos, Senior Vice President of Gannett Fleming Valuation and Rate Consultants, LLC.

By Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Dates and Discovery Guidelines, and Requiring Public Notice issued April 26, 2016, and corrected in the Errata Order issued on April 27, 2016 (collectively, Scheduling Order), the Commission declared the Company's Application to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for a period of up to 270 days from and after May 1, 2016. In addition, the Scheduling Order set the matter for public witness and expert witness hearings, required the Company to give notice of the hearings, established discovery guidelines, and established a date for petitions to intervene and for the prefiling of direct testimony by the Public Staff and other intervenors, and established a date for the filing of rebuttal testimony by the Company.

On May 31, 2016, Blue Ridge Paper Products Inc. d/b/a Evergreen Packaging (Evergreen) filed a Petition to Intervene. Evergreen's Petition was granted by Commission Order dated June 2, 2016.

On June 13, 2016, the Attorney General filed its Notice of Intervention pursuant to G.S. 62-20. Also on this date, PSNC, on behalf of attorney B. Craig Collins, filed a Motion for Admission to Practice pursuant to G.S. 84-4.1 seeking an order from the Commission allowing Mr. Collins to appear before the Commission on behalf of PSNC in this proceeding. By Order dated June 14, 2016, the Commission granted the request of Mr. Collins for admission pro hac vice in the present docket.

On June 16, 2016, PSNC filed affidavits of publication of public notice.

Between June 22, 2016 and September 21, 2016, the Commission received four consumer statements of position regarding PSNC's rate increase proposal.

On June 23, 2016, PSNC filed its Certification that it had provided Notice of Hearing to each of its customers.

On August 8, 2016, the Public Staff filed a Motion for Extension of Time in which it sought an extension of the dates for filing Public Staff, Intervenor, and Company rebuttal testimony. The Commission approved a shortened extension of time by Commission Order dated August 9, 2016.

On August 12, 2016, PSNC and the Public Staff filed a Joint Motion for Extension of Time in which the parties requested the Commission to reconsider its prior order and grant the extension period originally requested. The Commission approved the extension by Order dated August 17, 2016. On August 17, 2016, the Public Staff by verbal motion requested that the Commission grant the Public Staff and Intervenors an extension until noon of the following day within which to file their testimony. This motion was granted by Order dated August 17, 2016.

On August 18, 2016, PSNC, CUCA, Evergreen, and the Public Staff (Stipulating Parties) filed a Partial Stipulation resolving most of the issues between these parties. On the same date, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Director, Accounting Division; Michelle M. Boswell, Staff Accountant, Natural Gas Section, Accounting Division; Julie G. Perry, Supervisor of the Natural Gas Section of the Accounting Division; and Jan A. Larsen, Director of the Natural Gas Division.

On August 22, 2016, PSNC filed a Motion for Extension of Time in which it sought a two-day extension of time for PSNC to file a list of hearing witnesses and estimate of cross-examination times. On the same date, the Stipulating Parties filed a corrected page 7 of the Partial Stipulation.

On August 23, 2016, the Commission issued an Order granting PSNC's request for an extension of time to file the witness list and cross-examination estimate.

On August 24, 2016, PSNC filed the supplemental testimony of Robert B. Hevert. On the same date, PSNC filed its Witness List and Motion to Excuse Witnesses, wherein the Company, after consulting with all of the parties of record, provided the

proposed order of appearance of witnesses and estimates of cross-examination times. PSNC also requested in the filing that Company witnesses Harris, Boone, Spaulding, Jackson, and Spanos and Public Staff witness Larsen be excused from appearing at the expert witness hearing, since none of the parties had questions for these witnesses. PSNC also filed a Motion for Extension of Time requesting an extension until noon on August 25, 2016, for PSNC to file its rebuttal and supplemental testimony.

On August 23, 2016, the matter came on for a public witness hearing in Gastonia as scheduled. No person appeared to testify as a public witness.

On August 24, 2016, a public witness hearing was held in Asheville as scheduled. No person appeared to testify as a public witness.

By Order dated August 25, 2016, the Commission granted the Company's extension of time to file rebuttal and supplemental testimony.

On August 25, 2016, PSNC filed the supplemental testimony of Candace A. Paton, the rebuttal testimony of Jimmy E. Addison, and the rebuttal testimony of Candace A. Paton. On the same date, the Stipulating Parties filed an Amended Partial Stipulation. The Public Staff also filed an Amended Exhibit C, which amended page 2 of Public Staff witness Larsen's original filed Exhibit C in support of the Amended Partial Stipulation.

Also on August 25, 2016, a public witness hearing was held in Statesville as scheduled. No person appeared to testify as a public witness.

On August 29, 2016, the Commission issued an Order Denying in Part Motion to Excuse Witnesses, in which the Commission excused only Company witnesses D. Russell Harris, James A. Spaulding, and John J. Spanos from attending the expert witness hearing. In addition, the Commission accepted their testimony and exhibits into evidence.

Also on August 29, 2016, the Stipulating Parties filed a Stipulation and Exhibits by and between the Stipulating Parties resolving all issues between them. On the same date, PSNC filed the supporting supplemental testimony and Exhibits of Candace A. Paton, and the Public Staff filed witness Boswell's Revised Exhibit 1 in support of the Stipulation.

On August 29, 2016, a public witness hearing was held in Raleigh as scheduled. No person appeared to testify as a public witness.

On August 30, 2016, the Commission convened the final public witness hearing and the expert witness hearing in Raleigh as scheduled. No person appeared to testify as a public witness. On the same date, the Stipulating Parties filed an Amended Stipulation, which made corrections to the Stipulation filed on the previous day.

At the hearing, the Company reported, and the Stipulating Parties confirmed, that following substantial negotiations a comprehensive agreement had been reached between the Company, the Public Staff, CUCA, and Evergreen, and that this agreement resolved all issues in the case as between those parties, and that this agreement was reflected in the Amended Stipulation.

At the hearing, the various prefiled direct and supplemental testimony and exhibits of the following Company witnesses were offered and accepted into evidence by the Commission: D. Russell Harris, Jimmy E. Addison, Robert B. Hevert, John J. Spanos, George B. Ratchford, Sharon D. Boone, James A. Spaulding, Candace A. Paton, and Rose M. Jackson. Company witnesses Addison, Hevert, Ratchford, Boone, Paton, and Jackson testified at the hearing. The various prefiled direct testimony and exhibits of the following Public Staff witnesses were offered and accepted into evidence by the Commission: Michelle Boswell, Julie Perry, and Jan Larsen. Public Staff witnesses Boswell and Larsen testified at the hearing.

On September 1, 2016, the Public Staff filed two late-filed exhibits pertaining to the supporting workpapers and the calculation of the lead-lag working capital reflected in the Amended Stipulation pursuant to Commission request.

On September 6, 2016, PSNC filed Late-Filed Exhibits B and D and Revised Exhibit C to the Amended Stipulation.

On September 14, 2016, PSNC filed a letter with the Commission stating that it had reviewed the two late-filed exhibits filed by the Public Staff on September 1, 2016, which included work papers with updated adjustments to working capital, and agreed that the exhibits accurately reflect the information that Presiding Commissioner Brown-Bland requested PSNC to provide.

On October 10, 2016, PSNC and the Public Staff filed a Joint Proposed Order.

On October 10, 2016, the Attorney General filed a post-hearing Brief.

On October 14, 2016, PSNC filed a motion requesting leave to file a Reply Brief, and filed its proposed Reply Brief.

On October 19, 2016, the Attorney General filed a motion for leave to file a Response Brief, and filed his Response Brief.

The Commission hereby accepts the filing of PSNC's Reply Brief and the Attorney General's Response Brief.

Based upon the verified Application, the testimony and exhibits received into evidence at the hearings, the Amended Stipulation, the late-filed exhibits, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. PSNC is a corporation organized and existing under the laws of the State of South Carolina, duly authorized to do business in and engaged in the business of transporting, distributing, and selling natural gas within North Carolina.

2. PSNC is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over, among other things, the rates and charges, rate schedules, classifications, and practices of PSNC in its capacity as a public utility.

4. In the Application in this docket, PSNC is seeking approval of: (a) a general increase in and revisions to the rates and charges for customers served by the Company; (b) certain changes to the cost allocation, rate designs, and practices underlying existing rates for the Company; (c) changes to the Company's existing service regulations and tariffs; (d) implementation of a new Integrity Management Tracker (IMT) mechanism; (e) implementation of new depreciation rates; (f) proposed funding of gas distribution research and development activities conducted by the Gas Technology Institute (GTI); (g) authority to include $2,000,000 related to distribution integrity management program operations in the Company's cost of service; and (h) implementation of a rate decrement to refund to its customers over a one-year period the Company's excess deferred income tax balance as of December 31, 2015.

5. The Company is properly before the Commission with respect to the relief sought in the Application in this proceeding pursuant to the provisions of Chapter 62 of the North Carolina General Statutes, and the Commission's Rules.

Test Period

6. The parties submitting evidence in this case with respect to revenue, expenses, and rate base levels used a test period of the twelve months ended December 31, 2015, adjusted for certain known and measurable changes through June 30, 2016, or thereafter, and the Amended Stipulation was based upon the same test period.

7. The appropriate test period for use in this proceeding is the twelve months ended December 31, 2015, updated for certain known and measurable changes through June 30, 2016, or thereafter.

Amended Stipulation

8. In summary, the Amended Stipulation executed by PSNC, the Public Staff, CUCA, and Evergreen resolves all issues in this docket, and is actively supported or not opposed by all parties to this docket with the exception of the Attorney General.

9. After carefully reviewing the Amended Stipulation, the Commission finds and concludes that the Amended Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Increase

10. The Application seeks an increase in annual revenues for the Company of $41,583,020. The Amended Stipulation provides for a total increase in annual revenues for the Company of $19,054,160, of which $276,576 is recovered through the proposed increase in other operating revenues. The Commission finds and concludes that the revenue increase agreed upon in the Amended Stipulation is just, reasonable and appropriate for use in this proceeding.

Rate Base

11. The Stipulating Parties agreed that the original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina is $946,722,235, consisting of gas plant in service of $1,839,643,565, and working capital – lead lag of $13,714,498, reduced by accumulated depreciation of $657,141,088, working capital – other of $7,817,284, and accumulated deferred income taxes of $241,677,456, as set forth in Paragraph 4 and Exhibit A of the Amended Stipulation, the Public Staff Late-Filed Exhibit I, and reflected on Schedule 1 hereto. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

Revenues and Operating Expenses

12. The Stipulating Parties agree that the Company's end-of-period *pro forma* revenues under present rates for use in this proceeding are $434,445,667, comprised of $430,126,449 of sales and transportation revenues, $792,254 of special contract revenues, and $3,526,964 of other operating revenues, as set forth in Paragraph 5 and Exhibit A of the Amended Stipulation. The Amended Stipulation further details that the Company's *pro forma* annual operating revenues under the agreed upon rates, which are appropriate for use in this proceeding are $453,499,827, comprised of $448,904,033 of sales and transportation revenues, $792,254 of special contract revenues, and $3,803,540 of other operating revenues, as set forth in Paragraph 5 and Exhibit A of the Amended Stipulation. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

13. The Stipulating Parties agreed that the Company's operating expenses are $201,794,646, including actual investment currently consumed through reasonable actual depreciation, as set forth on Public Staff Late-Filed Exhibit I. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

Capital Structure

14. The capital structure set forth in Paragraph 5.B. of the Amended Stipulation and supported by expert witness evidence, consisting of 52.0% common equity, 44.62% long-term debt at a cost of 5.52%, and 3.38% short-term debt at a cost of 0.77%, is just, reasonable and appropriate for use in this docket.

Return

15. Based on the expert witness evidence and the Amended Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.53%, as set forth in Paragraph 5.D. and Exhibit A of the Amended Stipulation. This overall rate of return is just, reasonable and appropriate for use in this docket.

16. Based on the expert witness evidence and the Amended Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 9.70%, as set forth in Paragraph 5(C) of the Amended Stipulation. This rate of return on common equity is just, reasonable and appropriate for use in this docket.

17. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to PSNC's customers in light of changing economic conditions or otherwise.

18. With respect to the foregoing ultimate findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission relies on the following more specific findings of fact:

a. The overall rate of return on rate base and allowed rate of return on common equity underlying PSNC's current base rates are 8.54% and 10.60% respectively.[1]

[1] See In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in its Rates and Charges, Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, Docket No. G-5, Sub 495 (Oct. 24, 2008) (2008 Rate Order).

b. PSNC's current base rates became effective on November 1, 2008 and have been in effect since that date except for adjustments due to the Company's Customer Usage Tracker mechanism and state tax changes.

c. In its Application, PSNC sought approval for rates which were based on an overall rate of return on rate base of 8.14% and an allowed rate of return on common equity of 10.60%.

d. In the Amended Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.53% and an allowed rate of return on common equity of 9.70%.

e. The current Commission authorized allowed rate of return on common equity underlying Piedmont Natural Gas Company, Inc.'s base rates is 10.0%.[2]

f. The current Commission authorized allowed rate of return on common equity for Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Dominion North Carolina Power is 10.2%.[3]

g. Since January 1, 2014, a total of 24 of the 54 authorized rates of return on equity for natural gas utilities were 9.70% or above, with the average authorized rate of return on equity in all such cases being 9.65%.

h. In determining the rate of return on equity for PSNC, it is inappropriate to rely on past rate of return on equity determinations authorized for other utilities without evidence tying those determinations to the facts of this case. It is, however, appropriate to note such past determinations as a check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

i. The stipulated overall rate of return on rate base of 7.53% and allowed rate of return on common equity of 9.70% are supported by credible, competent, material, and substantial evidence.

j. Continuous safe, adequate, and reliable natural gas service by PSNC is essential to the well-being of the people, businesses, institutions and economy of PSNC's North Carolina service area.

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[2] Order Approving Partial Rate Increase and Allowing Integrity Management Rider, Docket No. G-9, Sub 631 (December 17, 2013).

[3] Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (September 24, 2013); Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013); and Order Granting General Rate Increase, Docket No. E-22, Sub 479 (December 12, 2012).

k. The rate of return on PSNC's equity approved by the Commission appropriately balances the benefits received by PSNC's customers from PSNC's provision of safe, adequate, and reliable natural gas in support of the well-being of the people, businesses, institutions, and economy of North Carolina, with the difficulties that some of PSNC's customers will experience in paying PSNC's increased rates.

l. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina and PSNC's service territory (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (i) unemployment rates were declining; (ii) real gross domestic product growth was continuing; (iii) median household income was growing; (iv) total personal income and disposable income was increasing; (v) personal consumption was improving; (vi) wages and salaries were increasing; (vii) the number of mortgages past due decreased; (viii) North Carolina exports were materially increasing; (ix) residential construction permits were increasing; and (x) housing market indicators were mostly positive. No public witnesses appeared at the public hearings held in Gastonia, Asheville, Statesville, and Raleigh.

m. The 9.70% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for PSNC because the Amended Stipulation reduced downward PSNC's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

n. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

o. PSNC has made significant capital investments since its last rate case in 2008, much of which relates to the Company's integrity management programs in compliance with federal regulations to enhance the safety and integrity of its natural gas transmission facilities. Additionally, the Company plans to make significant capital investments in the future.

p. Access to capital at reasonable rates is critical to PSNC's ability to fund its ongoing capital investment requirements and PSNC's provision of safe, adequate, and reliable natural gas.

q. Establishing an allowed rate of return on common equity at a rate of 9.70% is as low as reasonably possible without unduly jeopardizing PSNC's ability to access capital on reasonable terms.

r. The 9.70% return on equity and the 52.00% equity financing approved by the Commission in this case results in a cost of capital that will enable PSNC by sound management to produce a fair return for its shareholders, considering changing economic conditions, and is just, reasonable and fair to PSNC's customers. It appropriately balances PSNC's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

Throughput

19. For the purpose of this proceeding, the appropriate level of adjusted sales and transportation volumes is 937,082,412 therms, which is comprised of 491,921,582 therms of sales quantities, 316,664,980 therms of transportation quantities, and 128,495,850 therms of special contract quantities. The appropriate level of lost and unaccounted for gas is 7,027,614 therms and company use gas is 870,521 therms. The appropriate level of purchased gas supply is 499,819,717 therms, consisting of sales volumes and company use and lost and unaccounted for gas.

Cost of Gas

20. The total cost of gas reasonable and appropriate for use in this proceeding is $180,388,055, as described in Paragraph 7.B. and Exhibit E of the Amended Stipulation and consisting of $110,682,356 in commodity costs, $1,777,080 in company use and lost and unaccounted for costs, and $67,928,619 in fixed gas costs.

21. The Benchmark Commodity Cost of Gas reasonable and appropriate for use in this proceeding is $0.225 per therm, as described in Paragraph 7.A. of the Amended Stipulation subject to any filed changes in such rate prior to implementation of effective rates in this docket.

22. The fixed gas costs that should be embedded in the proposed rates and used in true-ups of fixed gas costs for periods subsequent to the effective date of rates in this docket, in proceedings under Commission Rule R1-17(k), subject to any filed changes in such costs prior to the effective date of rates in this docket, are those derived from the fixed gas cost allocation percentages discussed in Paragraph 5 of the Amended Stipulation and set forth in Exhibit C to the Amended Stipulation.

Rate Design

23. The rate design and rates, including volumetric rates, fixed monthly charges, and other charges, as described in Paragraph 5 of the Amended Stipulation and reflected in the columns entitled "Monthly Facilities Charges" and "Energy Charges" on Exhibit B of the Amended Stipulation (as the same may be adjusted for any changes in the Company's Benchmark or changes in Demand and Storage Charges prior to the effective date of the rates in this docket), are just, reasonable and appropriate for use in this docket.

Integrity Management Tracker

24. The IMT attached to the Amended Stipulation in Exhibit H is just, reasonable, appropriate and consistent with G.S. 62-133.7A, and should be approved and implemented as provided in Paragraph 10 of the Amended Stipulation, and Rider E of the Company's tariffs.

Customer Usage Tracker Factors

25. The "R" values, baseload and heat sensitive factors set forth on Late Filed Exhibit D to the Amended Stipulation and reflected in Paragraph 6 of the Amended Stipulation are reasonable and appropriate for use with the Company's Customer Usage Tracker (CUT) mechanism on or after the effective date of rates, and should be approved.

Amortization of Deferred Regulatory Assets

26. The proposed amortization of certain deferred regulatory assets, as set forth and described in Paragraphs 5(G) through 5(I) of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Implementation of State Income Tax Changes

27. The Stipulating Parties' agreement to decrease the North Carolina corporate income tax reflected in rates pursuant to North Carolina Session Law 2015-241, and as set forth in Paragraph 8 of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Depreciation Rates

28. The Stipulating Parties' agreement regarding the depreciation rates proposed by the Company as set forth in Paragraph 9 of the Amended Stipulation is just, reasonable and appropriate and should be approved effective January 1, 2017.

Changes to Tariff Rules and Regulations

29. PSNC's Tariff and Rules and Regulations included in witness Paton's Exhibit 4, with the exception of the Summary of Rates and Charges, Riders C and E, and the Transportation Pooling agreement, are just, reasonable and appropriate and should be approved. In addition, revised Riders C and E and the revised Transportation Pooling Agreement, as described in Paragraph 11 and Exhibit H of the Amended Stipulation, are just, reasonable and appropriate and should be approved.

Excess Deferred Income Taxes

30. The Stipulating Parties agreed to implement a temporary decrement in rates to refund excess deferred income taxes (EDIT) over a one-year period, as set forth in Paragraph 12 of the Amended Stipulation, and further agreed that any balance remaining after the twelve-months should be transferred to the All Customers' Deferred Account. This proposed treatment is just, reasonable and appropriate and should be approved.

Conservation Program Expenditures

31. The Stipulating Parties' agreement to continue funding of conservation programs at a level of $750,000 per year, as reflected in test year operating expenses and set forth and described in Paragraph 13 of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Gas Technology Institute Research Funding

32. The funding of GTI research and development activities of $268,631 per year, as discussed in Paragraph 14 of the Amended Stipulation and set forth in the Public Staff Late-Filed Exhibit I, is just, reasonable and appropriate and should be approved.

Miscellaneous Matters

33. Use of the overall rate of return, adjusted for income taxes, as the Allowance for Funds Used During Construction rate for the Company is just, reasonable and appropriate, and should be approved.

34. The Stipulating Parties agreed that beginning with the month in which rates become effective in this docket, PSNC will use an interest rate of 6.6% per annum as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in PSNC's Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The Stipulating Parties also agreed that the methods and procedures used by PSNC for the accrual of interest on the Deferred Gas Cost Accounts will remain unchanged. These provisions of the Amended Stipulation are just, reasonable and appropriate and should be approved.

35. The Stipulating Parties agreed that PSNC shall file its GS-1 Report in a format similar to the ES-1 Reports filed by the electric utilities. This is reasonable and appropriate and should be approved.

36. Beginning with the January 2017 report, PSNC shall add to its monthly report on the SCANA Utility Money Pool the net daily balance of loans and receipts, and the total net interest amount on the balances. This information will be provided for the month, and for the calendar year to date.

Consumer Statements of Position

37. Although not evidence in this proceeding, the Commission has read and given appropriate consideration to the consumer statements of position received by the Commission, the Public Staff and the Attorney General.

Acceptance of Amended Stipulation

38. The Commission finds and concludes in light of the evidence presented that the provisions of the Amended Stipulation are just and reasonable to the customers of PSNC and to all parties to this proceeding, and serve the public interest. Therefore, the Amended Stipulation should be approved in its entirety. In addition, it is entitled to substantial weight and consideration in the Commission's decision in this matter.

Just and Reasonable Rates

39. The Commission finds and concludes that the rates approved herein are just and reasonable to the customers of PSNC, to PSNC, and to all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, the Form G-1 that was filed with the Application, and the Commission's records as a whole. These findings are jurisdictional and procedural in nature and are not contested by any party.

On March 31, 2016, PSNC filed a verified Application for an increase in its base rates. In summary, the application seeks a $41,583,020 increase in PSNC's annual North Carolina revenues. This would be an overall increase of 9.66% in PSNC's revenue. Further, the application seeks approval of a 10.6% rate of return on common equity (ROE), an 8.14% overall return on rate base, and a capital structure of 53.5% common equity, 3.38% short-term debt, and 43.12% long-term debt. PSNC's present authorized ROE and overall return are 10.6% and 8.54%, respectively. PSNC's present authorized capital structure is 54% common equity, 10.5% short-term debt, and 35.5% long-term debt. Its authorized cost of debt is 3.25% for short-term debt and 6.96% for long-term debt. See Order Approving Partial Rate Increase, Docket No. G-5, Sub 495 (Oct. 24, 2008) (2008 Rate Order). The Application states that during the 12-month test period PSNC's overall rate of return on its North Carolina retail rate base was 7.84%.

According to the Application, since its last general rate case in 2008 PSNC's business has been impacted by a heightened awareness of and focus on pipeline safety, low and stable natural gas prices, the opportunity to acquire additional pipeline capacity, PSNC's need to invest in pipeline enhancement projects, and the expanded use of technology to more efficiently serve its customers. PSNC states that it has added 77,025 customers, installed over 1,424 miles of transmission and distribution mains, invested

approximately $609 million in its utility property, and incurred over $19 million in deferred environmental and pipeline safety costs.

In its Application, PSNC requests approval of a rider to its rates to provide for ongoing recovery of its capital costs related to pipeline safety improvements and management. In addition, PSNC recommends new annual depreciation rates based on a depreciation study conducted pursuant to Commission Rule R6-80. Further, PSNC seeks to update and revise certain tariff provisions, including changes to its industrial tariff and pooling agreement, and a new Medium General Service rate. Moreover, PSNC requests approval of a rate decrement for one year to refund to its customers an excess accumulated income tax balance of $7.3 million. PSNC requests that its new rates be effective on November 1, 2016.

PSNC is a public utility within the meaning of G.S. 62-3(23). Therefore, pursuant to G.S. 62-30, et seq., the Commission has jurisdiction to consider and decide PSNC's Application for a rate increase.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, and the Form G-1 that was filed with the Application.

The Company filed its Application and exhibits using a test period of the twelve months ended December 31, 2015. In its Order of April 26, 2016, the Commission ordered the parties to use a test period of the twelve months ended December 31, 2015, with appropriate adjustments. The Amended Stipulation is based upon the test period ordered by the Commission, and this test period is not contested by any party. In the Amended Stipulation, the Stipulating Parties agreed to make appropriate adjustments to the test period data for circumstances occurring or becoming known through June 30, 2016, or thereafter. These adjustments were not contested by any party.

The Commission finds and concludes that the Company's use of a test period of the twelve months ended December 31, 2015, with appropriate adjustments, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

These findings are supported by the testimony of Company witness Paton, Public Staff witness Hoard, and the provisions of the Partial Stipulation and the Amended Stipulation.

On August 25, 2016, PSNC, CUCA, Evergreen, and the Public Staff (Stipulating Parties) filed an Amended Partial Stipulation resolving most of the issues between the Stipulating Parties. For example, in Paragraph 5.H. the Stipulating Parties stated that they

agreed that it is appropriate to amortize and allow recovery of the balance of PSNC's deferred asset representing manufactured gas plant (MGP) clean-up costs, but did not agree on the balance of the deferred asset or the amount of the annual amortization expense. Similarly, in Paragraph 5.I., the Stipulating Parties stated that they agreed it is appropriate to amortize and allow recovery of the balance of PSNC's deferred asset representing PSNC's pipeline integrity management (PIM) costs, but did not agree on the balance of the deferred asset or the amount of the annual amortization expense.

On August 25, 2016, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Director, Accounting Division. Witness Hoard testified to the ongoing disagreement between PSNC and the Public Staff regarding the treatment of MGP clean-up costs, and PSNC's deferred PIM costs. In summary, witness Hoard testified to adjustments made to the amortization of PSNC's MGP and PIM costs that, if accepted by the Commission, would substantially reduce the Company's recovery of those costs in this rate proceeding.

On August 29, 2016, the Stipulating Parties filed the Amended Stipulation. The Amended Stipulation recites that it is filed on behalf of PSNC, the Public Staff, CUCA, and Evergreen. The Amended Stipulation further states that it represents a complete and integrated settlement of all matters at issue between the Stipulating Parties.

In her supplemental testimony filed on August 29, 2016, PSNC witness Paton testified that the Stipulating Parties engaged in substantial discovery regarding the issues involved in PSNC's Application. Witness Paton further stated that the Public Staff spent several days at PSNC's office in Gastonia and at SCANA's corporate office in Cayce, South Carolina, performing audits and interviewing Company employees. In addition, she testified that after lengthy negotiations in multiple meetings and conference calls, the Stipulating Parties reached a partial settlement on all but one issue in the case.[4] Witness Paton further testified that the Stipulating Parties reached agreement on the remaining issue, which resulted in the filing of the Amended Stipulation on August 29, 2016. Moreover, witness Paton testified that the Amended Stipulation was the result of give-and-take negotiations in which each Stipulating Party made substantial compromises on individual issues in order to obtain a compromise from other Stipulating Parties on other issues. She testified that the end result is a settlement in which each party believes that the aggregate results are fair to PSNC and its customers.

As the Amended Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the Amended Stipulation is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I the Supreme Court held that

[4] Witness Paton referenced "one issue in the case," which perhaps grouped the amortization of MGP and PIM deferred costs as one amortization issue.

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.
>
> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16 (emphasis added).

The Commission gives substantial weight to the testimony of PSNC witness Paton regarding the Stipulating Parties' efforts in negotiating the Amended Stipulation. Further, the Commission gives some weight to the fact that there was only an Amended Partial Stipulation as of August 25, 2016, and that the Public Staff filed testimony in support of its position on the unresolved issues. The Public Staff's filing of testimony in preparation for litigating the contested issues indicates the Public Staff's resolve and determination to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Amended Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance PSNC's need for increased revenues and its customers' needs to receive safe, adequate and reliable natural gas service at the lowest possible rates. In addition, the Commission finds and concludes that the Amended Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket that is supported, or not opposed, by all parties except the Attorney General. As a result, the Amended Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding is supported by the Application, the direct testimony and Exhibits of Company witness Boone, the supplemental testimony of Company witness Paton, the Amended Stipulation, the Public Staff's Late Filed Exhibit I, and the direct testimony of Public Staff witness Boswell.

Revised Boone Exhibit 6, attached to the direct testimony of Company witness Boone, indicates that the Company filed for a total revenue increase in this proceeding of $41,583,021. The Amended Stipulation, in Exhibit A, indicates that pursuant to the agreement of the Stipulating Parties the Company should be allowed to increase annual revenues by $19,054,160, of which $276,576 would be recovered through the proposed increase in other operating revenues. This increase in revenues is further reflected in the supplemental testimony and exhibits of Company witness Paton and the Revised Public Staff's Late Filed Exhibit 1. These findings are not contested by any party.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, including the discussion and analysis related to the proper rate of overall return and return on common equity for use in this proceeding, the Commission finds, in the exercise of its independent judgment, that the stipulated revenue increase in this case is just, reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, the Form G-1 that was filed with the Application, and the Amended Stipulation.

The reasonable original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina, less that portion of the cost that has been consumed by depreciation expense, is described and set forth in Paragraph 4 and Exhibit A to the Amended Stipulation, Public Staff Late Filed Exhibit I. The amounts shown on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Amended Stipulation, the direct testimony of Public Staff witness Boswell, and the supplemental testimony of Company witness Paton. The stipulated reasonable original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas service to the public, less depreciation expense, is not contested by any party.

No other party presented evidence on these matters.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's rate base, which collectively constitute the only evidence in this docket regarding the Company's rate base, and concludes that the stipulated amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding is set forth in the Amended Stipulation, Public Staff Late Filed Exhibit I, the supplemental testimony of Company witness Paton, and the direct testimonies of Public Staff witnesses Boswell and Larson.

The end of test period *pro forma* revenues under the Company's present and stipulated proposed rates are set forth in Paragraph 5 and Exhibit A to the Amended Stipulation, and Public Staff Late Filed Exhibit I to the Amended Stipulation. These amounts are the result of negotiations among the Stipulating Parties in this docket following an extensive audit of the Company's filed case by the Public Staff and are described in the Amended Stipulation. No other party submitted evidence on the Company's *pro forma* revenues, and the stipulated *pro forma* revenues are not challenged by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to *pro forma* revenues, and concludes based on its own independent judgment that the stipulated *pro forma* revenues are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is set forth in the testimony of Company witness McLeod, Public Staff Late Filed Exhibit I and the Amended Stipulation.

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Exhibit A to the Amended Stipulation, Public Staff Late Filed Exhibit I. The amounts shown on Exhibit A to the Amended Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Amended Stipulation and the supplemental testimony of Company witness Paton, and are not contested by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's reasonable operating expenses, and concludes that the stipulated reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding is contained in the prefiled direct testimony of PSNC witness Jimmy E. Addison, the prefiled direct and supplemental testimony of PSNC witness Robert B. Hevert, the hearing testimony of witness Addison and witness Hevert, and the Amended Stipulation.

In the Application, and as explained by PSNC witness Addison in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 43.12%, short-term debt of 3.38%, and equity of 53.50%. The short-term debt reflected the estimated average of gas inventory for the 13 months ending June 30, 2016, consistent with Commission practice. The long-term debt and equity figures reflected actual balances adjusted for forecasted changes through June 30, 2016. Witness Addison testified that PSNC planned to issue $100 million in unsecured long-term debt in June of 2016.

In his direct testimony, witness Hevert discussed the generally accepted approaches to developing the appropriate capital structure for a regulated natural gas distribution company, and explained how the capital structure affects the cost of capital and overall level of risk for the company. He explained that the capital structure should enable the company to maintain its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions. Witness Hevert then presented and provided support for his proxy group, described his analysis of the proxy companies' capital structures, and concluded based on his review that a capital structure consisting of 53.50% common equity, 3.38% short-term debt, and 43.12% long-term debt is reasonable and appropriate for PSNC. Witness Hevert explained the concept of maturity matching. He stated that, because it is perpetual in nature, adding equity to the capital structure extends the weighted average life of long-term liabilities, and mitigates incremental refinancing risk, but that relying more heavily on debt as the means of financing long-lived assets increases the risk of refinancing maturing obligations during less accommodating market environments.

Following settlement negotiations between PSNC, the Public Staff, CUCA and Evergreen, as reflected in Paragraph 5.B. of the Amended Stipulation, the Stipulating Parties proposed a capital structure of 52.00% common equity, 3.38% short-term debt and 44.62% long-term debt. The Stipulating Parties agreed to use 5.52% for the cost of long-term debt and agreed to use 0.77% for the cost of short-term debt.

In his supplemental testimony and associated exhibits, witness Hevert addressed the capital structure agreed to in the Partial Stipulation dated August 18, 2016 among PSNC, the Public Staff, CUCA, and Evergreen. (The Stipulating Parties filed two amended stipulations on August 25, 2016 and August 30, 2016, but those amended agreements did not adjust the capital structure reflected in the Partial Stipulation filed on August 18, 2016, to which witness Hevert testified.) In his supplemental testimony, witness Hevert stated that the capital structure ratios agreed upon by the Stipulating Parties fall well within the range of those in place at the proxy companies (from the first

calendar quarter of 2014 through the second calendar quarter of 2016), and that on that basis, he believed the stipulated capital structure to be reasonable.

No other party submitted testimony on the issue of the appropriate capital structure for the Company.

The proposed stipulated capital structure was also supported by the hearing testimony of PSNC witnesses Hevert and Addison. At the hearing in this matter, in response to cross-examination by the Attorney General, witness Addison confirmed that PSNC issued $100 million in unsecured long-term debt in June 2016 at a rate of 4.13%. Witness Addison also explained that PSNC operates in a “lumpy” business, in which it raises both debt and equity capital as needed to make required investments in rate base, which in turn results in different proportions of debt and equity at different points in time for the Company. He explained that if the debt ratio of capital structure is increased too much, the cost of debt would also increase due to the increased risk to debt investors. He testified that because PSNC’s actual equity component is slightly higher than 53.5%, but it will only receive the 9.70% stipulated ROE on the 52.0% equity contained in the stipulated capital structure, if the Commission approves the Amended Stipulation the shareholders’ actual return will be lower than the Company’s authorized return on equity. Witness Addison also explained the reasons for the differences in capital structure between PSNC and its parent company SCANA.

Also at the hearing, witness Hevert further supported witness Addison’s discussion of the reasons for higher cost of equity as compared to cost of debt. One of those reasons is that equity holders bear the “residual risk,” meaning they are last in line to receive cash flows generated by the Company, and receive what is left after the debt holders, who have a contractual claim on cash flows, are paid. Another reason is that the cost of debt is specified while the cost of equity is based on observable market information. Witness Hevert also testified that with respect to the proxy companies, the comparison to be made is the extent to which PSNC’s capital structure is consistent with the range of the proxy companies, rather than with their average, and that including short-term debt in the capital structure does not affect his conclusion that 52% equity in PSNC’s capital structure is reasonable. In various contexts, witness Hevert reiterated the value of using multiple sources of data in order to produce the range for capital structure.

Witness Hevert also discussed his rationale for looking primarily to the operating company level for determining the appropriate capital structure. He testified that utilities in general are required to finance very large, essentially irreversible long-lived investments, and have to be able to enter the capital markets at any given point in time, regardless of market conditions, and do not have the ability or option to defer those decisions. He noted that there are a number of approaches to developing the appropriate capital structure, and the reasonableness of the approach used depends on the nature and circumstances of the subject company. He testified that if a company does not issue its own securities, it may be reasonable to look to the parent’s capital structure, or to develop a “hypothetical” capital structure based on the proxy companies or other industry data. However, if the

company issues its own securities, as does PSNC, and if its capital structure is reasonable in reference to industry practice, it is not necessarily important to look at the parent company's capital structure. Witness Hevert concluded that in PSNC's case it is reasonable to look at the operating company level in setting the appropriate capital structure, rather than looking at SCANA.

Counsel for the Attorney General questioned witnesses Addison and Hevert about other approaches to viewing capital structure. On redirect, witness Hevert stated that the Value Line common equity ratios for the proxy companies include 55% for Atmos, 58% for New Jersey Resources, 56% for Northwest Natural, and 49% for Laclede. He noted that these data showed that distribution companies had much higher equity ratio expectations from Value Line as compared to SCANA, the holding company, with a 46% equity ratio.

On October 10, 2016, the Attorney General filed a post-hearing Brief. In summary, the Attorney General states that small increases or decreases in the ratio of equity financing versus debt make a large difference in the utility's revenue requirement, because equity is much more expensive, particularly when the cost of income taxes is taken into account. The Attorney General includes several tables demonstrating the impact of different capital structures on the Company's revenue requirement. In addition, the Attorney General criticizes witness Hevert's updated capital structure evidence included in his supplemental testimony because witness Hevert added two more recent calendar quarters to his original analysis of eight quarters. The Attorney General states that when the average equity ratio is calculated for witness Hevert's proxy companies using the same eight periods as in his original testimony, the equity ratio averages 49.69%, and when calculated using the most recent eight periods, the equity ratio averages 48.73%. Moreover, the Attorney General asserts that PSNC's holding company, SCANA, maintains an equity ratio that has typically been less than 45% during the last five years. In addition, the Attorney General notes that during the 56 months from March 2010 through October 2014 PSNC loaned money to the SCANA Utility Money Pool (UMP) in all but one month. The Attorney General interprets this to mean that PSNC had more cash available for its operating costs than PSNC needed. In conclusion the Attorney General states that it is reasonable and appropriate for PSNC to use a 45% equity ratio.

On October 14, 2016, PSNC filed a Reply Brief. With regard to the Attorney General's arguments on capital structure, PSNC submits that the Attorney General on several occasions makes inferences that are not supported by the witnesses' testimony. As an example, PSNC notes the Attorney General's argument concerning PSNC's loans to the UMP. PSNC contends that witness Addison's testimony actually supports the conclusion that PSNC's loans to the UMP coincide with issuances of long-term debt, noting his testimony that "PSNC is going to be moving back into that period where they're going to likely be a net borrower until the points that we go out and issue long-term debt." (T Vol. 5, p. 117) Further, PSNC states that this is borne out by the reports the Company filed in Docket No. G-5, Sub 422, on financings it made in March 2010 and February 2011, and the reports of its UMP activities filed in

Docket No. G-5, Sub 484, as referenced in Commissioner Brown-Bland's question to witness Addison. (T Vol. 5, p. 116)

In addition, PSNC maintains that the Attorney General's focus on the average equity ratios of witness Hevert's proxy companies is inapposite for two reasons. First, the equity balances used by witness Hevert are end-of-month, and therefore not necessarily representative of the average balances during the course of the month. Secondly, it is the range of results and not the average that is relevant to the analysis of the proxy group's capital structure.

On October 19, 2016, the Attorney General filed a Response Brief. With regard to PSNC's loans to the SCANA UMP, the Attorney General takes issue with PSNC's characterization of witness Addison's testimony as showing these loans coincided with issuances of long-term debt by PSNC. Rather, the Attorney General notes that witness Addison testified that during "the historical period" from 2010 to 2014, PSNC did not have as many capital investments to make as it will prospectively, "so we've not had to issue a great deal of long-term debt, anything like that, not been into the commercial paper markets a lot in the past." (T Vol. 5, p 117)

With respect to witness Hevert's conclusion regarding the equity ratios of his proxy companies, the Attorney General notes that witness Hevert's support of a 52% equity ratio for PSNC means that his position is at the high end of the equity range for the proxy group. The Attorney General posits that this is a pattern in witness Hevert's results, wherein he tends to recommend the high end of the range rather than the mid or low points.

The Attorney General's contentions with regard to witness Hevert's proxy group of utilities and their average equity financing are not persuasive. The Commission does not view witness Hevert's addition of two more current quarters to his analysis as discrediting witness Hevert's conclusions. In addition, the data and analytical tool used by witness Hevert was intended to produce a meaningful range of equity ratios for his proxy companies. The Attorney General attempts to use the data and tool for a different purpose – to compute the average equity ratios of the proxy companies. The Commission is not persuaded that the use of the data in this manner produces probative or reliable evidence regarding the equity ratios of the proxy companies.

With regard to the comparison of the capital structure of SCANA with that of PSNC, witness Addison explained that one reason for SCANA's higher debt ratio is approximately $700 million in debt that SCANA issued to purchase PSNC and is now being carried by SCANA. He described this as an unusual situation for SCANA, noting that it is the only time that SCANA has issued debt during his tenure as chief financial officer. Witness Addison also noted that SCANA's other regulated utilities have a capital structure similar to that of PSNC.

The Attorney General did not provide a witness or affirmative evidence that would support a capital structure, particularly a 45% common equity component of

capital structure. Indeed, no expert witness provided an analysis after the Amended Stipulation that showed 52% as the appropriate level of equity financing for PSNC. Therefore, the Commission must consider the evidence and exercise its independent judgment in determining the appropriate capital structure for PSNC in the context of setting PSNC's rates.

The Commission gives substantial weight to witness Addison's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. The Commission finds credible his explanation that increasing the debt ratio of PSNC's capital structure too much can lead to an increase in the cost of debt, as debt investors see more risk in the higher debt level. The Commission also gives significant weight to witness Addison's testimony regarding the reasons for the differences in capital structure between PSNC and its parent company SCANA. The Commission finds credible his explanation that one reason SCANA has a higher debt ratio is its issuance of approximately $700 million of debt to finance the purchase of PSNC.

In addition, the Commission gives significant weight to witness Hevert's testimony regarding the differences in the financing needs of holding companies and operating companies. The Commission finds credible witness Hevert's explanation that utilities generally are required to finance very large, long-lived investments, and may find it necessary to enter the capital markets at any given time. Thus, the appropriate mix of debt and equity for a public utility operating company can be significantly different from that of its holding company.

Based on the above-discussed capital structure testimony of witnesses Addison's and Hevert, the Commission finds their recommendations regarding the appropriate capital structure of PSNC to be substantial and credible evidence.

Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the amended stipulated capital structure and costs of long-term and short-term debt are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-18

The evidence supporting these findings is contained in the Application, the prefiled direct and supplemental testimony and Exhibits of Company witnesses Addison and Hevert, the hearing testimony of witnesses Addison and Hevert, and the Amended Stipulation. No other party submitted expert testimony on the appropriate overall rate of return on rate base (ROR or Overall Return) or allowed rate of return on common equity (ROE) appropriate for use in this proceeding.

Summary of the Evidence on Return

PSNC's current allowed rate of return on common equity, established by the Commission in 2008 in Docket No. G-5, Sub 495, is 10.6%.[5] Its current approved overall rate of return on rate base is 8.54%.[6] In its Application, PSNC proposed that the allowed rate of return on common equity in this proceeding be established at 10.6%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 8.14%.

PSNC's original return on common equity request was supported by the direct testimony and Exhibits of PSNC witnesses Addison and Hevert. Witness Hevert, who holds a Bachelor of Arts degree in business and economics and a Master of Business Administration with a concentration in finance, and is designated as a Chartered Financial Analyst and is a Partner with the ScottMadden, Inc. consulting firm, served as PSNC's cost of equity witness. Witness Hevert filed direct testimony and 13 exhibits in support of PSNC's request for 10.6% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and Exhibits document the specific analyses he conducted in support of PSNC's rate filing and provides a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

Witness Hevert testified that it is important for a utility to be allowed the opportunity to earn a return adequate to attract equity capital at reasonable terms and commensurate with the returns expected elsewhere in the market for investments of equivalent risk, because that enables the utility to provide service while maintaining financial integrity. He stated that the Commission's decision should provide PSNC with the opportunity to earn an ROE that is (1) adequate to attract capital at reasonable terms, thereby enabling it to continue to provide safe and reliable natural gas service; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.14% to 11.32% ROE, the results of his Multi-Stage DCF analysis

[5] See 2008 Rate Order.
[6] Id.

were a range of 8.96% to 10.07%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.26% to 11.97%. The results of witness Hevert's CAPM analysis showed a range of 9.13% to 11.42%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 9.98% to 10.39%. Based on his analyses, Witness Hevert concluded that a rate of return on common equity in the range of 10.00% to 10.75% represents the range of equity investors' required rate of return for investment in natural gas utilities such as PSNC. Within that range, he recommended an ROE of 10.6%.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) the combined dilutive effects of operating expense increases and increasing capital investments on the Company's operating income; (2) the Company's relatively high capital expenditure program; (3) the Company's relatively small size; (4) the effect of the proposed infrastructure recovery mechanism on the Company's cost of equity; and (5) the regulatory environment in which the Company operates. He also considered equity flotation costs. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the state and 5.30% in PSNC's service territory. He also noted that in 2014 the state exceeded the national rate for real gross domestic product growth, and that since 2009 median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, while housing permits and housing starts experienced a decline from late 2015 to early 2016, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Witness Hevert also testified to recent business expansions in the state. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within PSNC's service area continue to steadily emerge from the economic downturn that prevailed during the Company's 2008 rate case, and have experienced significant economic improvement during the last several years, that is projected to continue. In his opinion, PSNC's proposed ROE was fair and reasonable to PSNC, its shareholders and its customers, considering the impact of changing economic conditions.

Witness Hevert also addressed the capital market environment, and reiterated that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity, as exemplified by his use of the DCF, CAPM and Bond Yield Plus Risk Premium approaches.

In his direct testimony, witness Addison, Executive Vice President and Chief Financial Officer for PSNC, stated that, based on his training, experience, and knowledge of the financial community and how it perceives PSNC, he agreed with witness Hevert's conclusion that a 10.60% ROE is appropriate in this case. Witness Addison explained that adopting an unduly low ROE would ignore the changing economic conditions being experienced nationally and in North Carolina and could increase the cost of capital, a cost ultimately borne by PSNC's customers.

As reflected in Paragraph 5.C. of the Amended Stipulation, the Stipulating Parties agreed to a stipulated ROE of 9.70%. As stated in Paragraph 5.D. of the Amended Stipulation, the Stipulating Parties also agreed that PSNC should be allowed to earn an overall rate of return on its rate base of 7.53%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Amended Stipulation were supported by the supplemental testimony of PSNC witness Hevert and the hearing testimony of witnesses Hevert and Addison.

In his supplemental testimony and associated exhibits, witness Hevert addressed the agreed-upon ROE and overall rate of return agreed to in the August 18, 2016 Partial Stipulation. As with capital structure discussed above, while the Stipulating Parties filed two amended stipulations – one on August 25, 2016 and one on August 30, 2016 - those amended agreements did not adjust the stipulated ROE and overall rate of return reflected in the Partial Stipulation filed on August 18, 2016, to which witness Hevert testified. Witness Hevert testified to his understanding that the Stipulating Parties agreed to an ROE of 9.70%, with an overall rate of return of 7.53%. Witness Hevert stated that he supported PSNC's decision to agree to the stipulated ROE, explaining that although 9.70% is somewhat below the lower bound of his recommended range (i.e., 10.00%), he recognized that the Partial Stipulation represents a give and take among the Stipulating Parties regarding multiple issues that would otherwise be contested. He stated further that if the Company determined that the terms of the Partial Stipulation, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at reasonable cost rates, then he appreciated and respected that decision, and viewed the 9.70% stipulated ROE as a reasonable resolution of an otherwise contentious issue.

In his supplemental testimony, witness Hevert also updated his cost of capital analysis. He considered the stipulated ROE in the context of authorized returns for other natural gas utilities, finding that since January 1, 2014, a total of 24 of 54 returns authorized for natural gas utilities were 9.70% or above, with the average authorized ROE over all such cases being 9.65%. He again testified that North Carolina is generally considered to have a constructive regulatory environment, and in that context noted that the stipulated ROE is a reasonable, though conservative, measure of PSNC's cost of equity.

Witness Hevert also updated his review of economic conditions in North Carolina with respect to those factors for which updated data was available. He found that by 2015, North Carolina's real GDP exceeded its 2010 level by nearly 7.00%, and that from 2013 through 2015 the state's average rate of real GDP growth was somewhat higher than the national average. As to the rate of unemployment, he found that although North Carolina's December 2015 seasonally adjusted unemployment rate of 5.60% was somewhat higher than the U.S. average of 5.00%, by June 2016 both the national and North Carolina unemployment rates fell to 4.90%, with the rate in PSNC's service territory being only slightly higher at 5.14%. He found that personal income and consumption in the state have continued to expand at the national level. Finally, he reported that in its August 2016 "Snapshot of North Carolina," the Federal Reserve Bank of Richmond (FRB-Richmond) concluded that North Carolina's economy strengthened as total employment grew notably, household conditions continued to improve, and housing market indicators were mostly positive. The FRB-Richmond also observed that: (1) North Carolina employers added 19,400 jobs in June and almost every industry expanded payrolls that month; (2) the state's unemployment rate fell 0.2 percentage points to 4.90% in June and declined 0.9 percentage points since June 2015, and during the first quarter of 2016, the share of mortgages with payments 90 or more days past due fell 0.2 percentage point to 1.50%; and (3) North Carolina issued 5,210 new residential permits in June, up 7.10% from the prior month and up 11.9% from June 2015. Witness Hevert also noted that the models used to estimate the cost of equity reflect capital markets and therefore general economic conditions. He noted further that given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates. In summary, witness Hevert stated that it continues to be his view that on balance, the regional economic challenges in the state are substantially similar to those in the rest of the country, and that economic data regarding North Carolina and the United States do not alter the cost of equity estimates, or his recommendation, one way or the other.

Finally, witness Hevert considered the stipulated overall rate of return, stating that it is consistent with the average return authorized across the country, but lower than those returns authorized in the top-ranked regulatory jurisdictions, and that the stipulated overall rate of return is, like the stipulated ROE, reasonable, though in his opinion a conservative estimate of PSNC's overall investor-required rate of return.

At the hearing, in response to cross-examination by the Attorney General, witness Addison reiterated that two reasons for the higher cost of equity than cost of debt is that the equity investor requires more return commensurate with the higher risk associated with equity, and that while interest on debt is tax-deductible, equity earnings are not.

Witness Hevert also responded to cross examination by the Attorney General regarding his use of the DCF, CAPM, and Bond Yield Plus Risk Premium approaches to determine a recommended ROE range for PSNC. Witness Hevert confirmed the nature of his ROE recommendations in recent electric rate cases in North Carolina. He also

explained the value of using diverse sources of data for purposes of conducting the constant growth DCF analysis, discussed why he uses projected earnings to determine growth for the same analysis rather than another metric such as projected dividends, and testified that using different sources for the GDP for his multi-stage DCF would produce different results. During this discussion he answered questions from the Attorney General related to data on natural gas companies that are comparable to PSNC provided by Value Line. He also responded to questions regarding the source data he used for risk premiums for his CAPM analysis, and testified that use of some alternative sources would result in very low estimated ROEs that would have significant adverse impacts to the Company's financial standing. With regard to his Bond Yield Plus Risk Premium approach, witness Hevert clarified the nature and value of the numerous authorized rates of return on equity he used in that analysis, which in turn reflect market data.

In response to questioning by Chairman Finley, witness Hevert confirmed his belief that equity investors make investment decisions based on the risks they observe for the companies in which they are interested. He also clarified the distinction between expected and required returns, such that if the return that an investor requires is higher than the return that investor expects, that investor will choose not to invest. Witness Hevert testified that if a company operates in a state with poor economic conditions, such that many of its customers are unable to pay their bills, that company would have a large amount of uncollected revenues for the services it provided, which would in turn cause that company's risk to increase and the cost of equity that the equity investor would require to be higher. He testified further that, if the rate of return on equity was based on current economic conditions, and if in that scenario the investor was penalized during poor economic conditions by giving him less rate of return, symmetry would suggest that a higher return on equity would be provided during robust economic conditions. Witness Hevert also testified that, in comparison to the economic conditions that existed when previous electric rate cases were decided involving Duke, Progress, and Dominion North Carolina Power that were referenced by the Attorney General, the North Carolina economy has improved. Witness Hevert explained that the unemployment rate in the state is down considerably and is now approximately equal to the national rate, and that state GDP growth has expanded with projections for continued expansion. He agreed that the investment community looks upon the Commission, together with the state legislature and executive branch, as providing a constructive regulatory environment. He also agreed that the previous cases referenced by the Attorney General were, after remand to the Commission, reapproved at the same rates.

In response to further questioning by Chairman Finley, witness Hevert testified that, if it became a permanent requirement in North Carolina that the Commission change the rate of return on equity based on customers' ability to pay, that would have a negative impact on the constructive regulatory environment in the state. He explained that would be a departure from the Commission's past practice and would also be a departure from well-established practice of other regulatory commissions, which added together would add a considerable amount of risk. Witness Hevert further confirmed in response to questioning by Chairman Finley that other regulatory commissions will take economic conditions into consideration. He testified that, in this way, such commissions

balance the interests of investors and ratepayers. However, he stated that he was unaware of any regulatory commissions that apply adjustments to the return on equity to account for economic conditions or customer ability to pay.

No other party presented direct evidence on the Company's cost of capital or overall rate of return on rate base.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[7] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

In Bluefield, the United States Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 692-93.

In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

[7] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Imp. Co. v. Public Service Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield).

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope). To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id. at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "…the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[8] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the Hope and Bluefield Comparable Risk, Capital Attraction, and Financial Integrity standards.

The Commission also has found that the role of cost of capital experts is to recommend to the Commission the investor-required return, not to estimate increments or decrements of return in connection with consumers' economic environment. As the Commission pointed out:

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[8] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, at 24 (Sept. 24, 2013); see also North Carolina Utilities Commission, Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider at 26, (Dec. 17, 2013) (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"), DNCP Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of Hope. This the Commission has done.[9]

The Supreme Court agreed, and upheld the Commission's Order on Remand.[10] The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[11] In Cooper II, which addressed an appeal of the Commission's order on Dominion North Carolina Power's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[12] The Commission made such additional findings of fact in its order on remand.[13]

On October 10, 2016, the Attorney General filed a post-hearing Brief. With regard to the appropriate ROE for PSNC, the Attorney General contends that the stipulated 9.70% ROE is a higher ROE than what is adequate. As an example of the interrelationship between changes in the ratio of equity financing versus debt and the impact on the ROE, the Attorney General states that the proposed overall rate of return in the present case, 7.53%, is higher than the overall rate of return the Commission approved for Piedmont three years ago, 7.51%, in Docket No. G-9, Sub 631, even though the approved ROE for Piedmont was 10.0%. Further, the Attorney General asserts that capital costs have trended downward since Piedmont's rate case.

In its Reply Brief, PSNC asserts that the Attorney General's citation to the Transcript, Vol. 5, p. 75, does not support the above assertion. PSNC states that on this page of the Transcript PSNC witness Addison testified on cross-examination that Piedmont's lower overall rate of return in Docket No. G-9, Sub 631, as compared to the stipulated rate of return in this case, may have been due to the lower percentage of equity in Piedmont's capital structure as compared to the stipulated equity in this case. Further, PSNC states that witness Addison also testified that the 9.70% stipulated return

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[9] North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, at 34 – 35 (October 23, 2013); see also DNCP Remand Order at 26 (stating that the Commission is not required to "isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity").

[10] State of North Carolina ex rel. Utilities Commission v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014).

[11] State of North Carolina ex rel. Utilities Commission v. Cooper, 367 N.C. 430, 437, 758 S.E.2d 635, 642 (2014) (Cooper II); see also State of North Carolina ex rel. Utilities Commission v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[12] Cooper II, 367 N.C., at 438, 758 S.E.2d, at 643.

[13] DNCP Remand Order, at 4-10.

on equity in the present docket is higher than PSNC's embedded cost of long-term debt of approximately 5.5%.

In addition, PSNC asserts that there is no evidence that capital costs have trended downward since Piedmont's rate case. Rather, PSNC contends that witness Hevert's direct testimony indicates that capital costs have increased since Piedmont's rate case, noting that witness Hevert testified that "since December 2013, relative volatility has increased, suggesting greater increasing uncertainty in the natural gas utility industry"; "credit spreads have increased"; "[t]o the extent that credit spreads have increased, it is an observable measure of the capital markets' increased risk aversion"; and "increased risk aversion clearly is associated with an increased Cost of Equity." (T Vol. 5, p. 204)

In his Response Brief, the Attorney General states that the full Transcript citation should have been Vol. 5, pp. 73-75. Further, he notes that the point of comparing Piedmont's cost of equity and capital structure is to highlight the fact that the lower ROE in this case is deceptive because the 52% equity ratio offsets it.

With regard to the downward trend in capital costs, the Attorney General notes witness Hevert's testimony that stock prices for utilities went up in late 2015 and early 2016, which effectively reduced the dividend yield for shareholders. In turn, this tended to produce a lower cost of capital under the Constant Growth DCF analysis.

Most of the Attorney General's ROE argument focuses on criticism of the techniques used and results obtained by witness Hevert. With respect to witness Hevert's DCF analysis, the Attorney General asserts that there are two features that skew his results. One is his reliance on what the Attorney General calls "the most extreme data." That is, witness Hevert calculates his "High ROE" from the highest growth data that exists. However, as the Attorney General notes, witness Hevert also calculates a "Low ROE" from the lowest growth data, but his recommended ROE range draws from the high results, not the low results. The other feature that the Attorney General contends skews witness Hevert's DCF results upward is his over-reliance on sources of data that reflect five-year projections of annual growth in earnings per share -- Zack's, First Call, and Value Line -- without consideration of other factors available to investors for measuring growth. For example, the Attorney General points out that there are 15 measures of growth provided in Value Line reports for witness Hevert's proxy companies, including the annual rates of change per share for revenues, cash flow, earnings, dividends, and book value, each provided for the past 10 years, the past 5 years, and as estimates for future years.

In its Reply Brief, PSNC contends that the Attorney General's assertion that witness Hevert considered only the high range of his analysis is not supported by the record. PSNC cites witness Hevert's cross-examination testimony stating that he took into account both the high and low estimates of the growth data, and notes that his Table 2: Summary of Constant Growth DCF Results (T Vol. 5, p. 147) shows that his recommended ROE range of 10.00% to 10.75% did not draw only from the high results,

which ranged from 11.08% to 11.32%, but was within the overall range of high and low results.

With regard to the Attorney General's criticism that witness Hevert's DCF study did not consider factors other than earnings growth, PSNC cites witness Hevert's cross-examination testimony explaining why it was appropriate to use earnings growth and not the other factors. For example, witness Hevert stated that it was better to use earnings growth than dividends "simply because … the dividends are derived from earnings. You cannot pay dividends unless you have earnings." (T Vol. 6, p. 25) He further testified that he did not give historical earnings growth any weight, in part, "because a lot of analysts will already look at historical earnings growth and they would be reflected in the earnings projected." (T Vol. 5, p. 26)

In response, the Attorney General notes that witness Hevert agreed that the "mean high" estimate in his Constant Growth DCF study reflects the highest result based on the multiple growth data sources he used, and the "mean low" estimate reflects the lowest result, and that his 10.6% ROE recommendation is higher than the midpoint between the mean results and the highest results. With regard to witness Hevert's exclusive use of earnings growth, the Attorney General points out that other measures of growth are available to investors, and that relying on only one factor may have distorted witness Hevert's results, and asserts that this was illustrated by the Value Line information available to investors provided as an attachment to the Attorney General's Brief, as well as the box showing the growth data for Laclede Group.

With regard to witness Hevert's Multi-Stage DCF analysis, the Attorney General contends that his results are skewed upward by his use of a 5.31% long-term growth rate that he calculated, rather than using lower growth rates available from reliable sources such as the Social Security Administration (SSA), 4.35%, and the Energy Information Administration (EIA), 4.24%. In its Reply Brief, PSNC states that witness Hevert explained during cross-examination that the SSA and EIA growth rates are "not necessarily" lower than his if scenarios other than the SSA's and EIA's reference cases are considered. He stated that these alternative scenarios produce high and low case scenarios, and concluded that his estimate was "well within the range" of the high and low case scenarios that SSA and EIA provide. (T Vol. 6, pp. 33-34)

In response, the Attorney General notes witness Hevert's cross-examination testimony that he used the SSA and EIA rates in recent testimony that he filed in a Missouri rate case.

With respect to witness Hevert's CAPM analysis, the Attorney General asserts that his results are skewed because instead of relying on a published market source to estimate the risk premium associated with stocks, generally, compared to risk-free investments, witness Hevert derived his own risk premium estimates by performing a DCF study using data obtained from Bloomberg and Value Line. The Attorney General presents calculations derived by substituting the risk premium provided in a "Client Alert" issued by Duff & Phelps, an investor service that publishes data on the market

risk premium and investor expectations regarding that parameter, which produces lower CAPM results.

In reply, PSNC states that in witness Hevert's cross-examination testimony he notes that the Duff & Phelps estimated risk premium of 5% to 5.5% is not their CAPM approach but only one component of their "building block approach" under which other risk factors would be layered on to this component to calculate the cost of equity. (T Vol. 6, pp. 40-41) PSNC also states that witness Hevert testified that using this 5% to 5.5% risk premium would produce a cost of equity of only 7.49%, which would result in significant negative market consequences. PSNC further states that the Attorney General concedes that "data published by Duff & Phelps … may not be appropriate to determine a point-estimate for the cost of equity capital in this proceeding …." See Attorney General's Brief, at pp. 23-24.

The Attorney General responds that PSNC's position is contrary to the following statement in the Duff & Phelps Client Alert summary that was introduced as Attorney General Hevert Cross-Examination Exhibit 5:

> The ERP [Equity Risk Premium] is a key input used to calculate the cost of equity capital within the context of the Capital Asset Pricing Model (CAPM) and other models.

With respect to witness Hevert's Bond Yield Plus Risk Premium analysis, the Attorney General asserts that this approach does not rely on financial market data, but rather on the authorized rates of return that have been established by regulatory agencies for other utilities. The Attorney General states that the authorized rates of return were determined in other jurisdictions based on policies and underlying data estimates of market conditions that are not provided in the record in this case, and, therefore, it is not appropriate for the Commission to determine PSNC's ROE based on such evidence. In support of his position, the Attorney General cites State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 430, 443, 758 S.E.2d 635, 643 (2014); and State ex rel. Utilities Comm'n v. Public Staff, 331 N.C. 215, 225, 415 S.E.2d 354, 361 (1992).

In conclusion, the Attorney General submits that PSNC has not shown that a 9.70% ROE is required. Rather, the Attorney General maintains that market-based data indicates that the Company's cost of equity is at least 35 basis points lower than 9.70%.

As witness Hevert testified, the cost of equity is not precisely quantifiable. Therefore, financial analysts use a number of quantitative models to develop estimates from market data. Witness Hevert further testified that analysts must exercise some judgment in making assumptions and using proxies. The Attorney General's criticisms of witness Hevert's DCF and CAPM analyses constitute disagreements with witness Hevert about some of his judgments in choosing the market data that he uses in his quantitative models. The Commission is not persuaded that the Attorney General's criticisms undermine or reduce the credibility of witness Hevert. Rather, the Attorney General's criticisms go to the weight of witness Hevert's DCF and CAPM analyses and testimony,

and the Commission has given those criticisms due consideration in weighing witness Hevert's analyses and testimony.

With regard to witness Hevert's Bond Yield Plus Risk Premium (Bond Plus) analysis, the Commission has not relied on that analysis or witness Hevert's testimony regarding the Bond Plus analysis to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions.

The Attorney General did not provide a witness or affirmative evidence that would support a ROE lower than the stipulated 9.70%. Indeed, no expert witness provided an analysis after the Amended Stipulation that showed 9.70% as the appropriate level of ROE for PSNC. Therefore, the Commission must consider the evidence and exercise its independent judgment in determining the appropriate ROE for PSNC in the context of setting PSNC's rates. With these legal principles in mind, the Commission now turns to the analysis and weighing of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper).

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this in its Order Granting General Rate Increase in Docket No. E-22, Sub 479: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." Order Granting General Rate Increase, Docket No. E-22, Sub 479, at 38 (2012) (DNCP Rate Order).

The only evidence in this proceeding related to the determination of an overall rate of return on rate base or allowed rate of return on common equity is provided in the testimony and exhibits of PSNC's witnesses Addison and Hevert. Therefore, the substantial expert return on equity evidence that is entitled to the greatest weight is not contradicted by any direct cost of capital expert testimony. Witness Hevert indicated in

his supplemental testimony that, although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.0%), he views the 9.70% stipulated ROE as a reasonable resolution of an otherwise contentious issue. Witness Hevert also presented supplemental testimony in which he updated his analysis of the changing economic conditions in North Carolina. The analysis included a review of a number of economic statistics regarding the condition of the economy in North Carolina that continue to indicate improving economic conditions. Based on this analysis witness Hevert testified that economic conditions in the state do not alter his cost of equity estimates or recommendations one way or the other.

In his direct testimony, witness Addison testified to the importance of PSNC maintaining its ability to access national capital markets on reasonable terms in this time of financial uncertainty, an ability that ultimately benefits PSNC's ratepayers. He noted that return on equity is a key consideration for investors when assessing whether to invest in a company like PSNC. He highlighted the Company's significant and ongoing capital needs as well as the important and real financial consequences that the Commission's determinations regarding rate of return can have in the capital markets and the terms under which PSNC can access those markets.

The Attorney General questioned witness Hevert about various aspects of his analysis, but did not provide any affirmative evidence that would support a return on common equity lower than the 9.70% proposed in the Amended Stipulation. The Attorney General's cross-examination established only that the outcomes of the DCF and CAPM analyses would have been different had witness Hevert, for example, used different sources for the growth estimate in the third stage of the multi-stage DCF analysis, or had he used another approach to the CAPM method. The Commission finds witness Hevert to be a credible witness in this case and accepts witness Hevert's support of the 9.70% ROE as probative evidence for purposes of establishing a return on common equity for PSNC in this proceeding. The Commission notes that witness Hevert's direct and supplemental testimony is the only economic rate of return testimony in this case.

There is no record evidence in this case establishing meaningful customer opposition to the stipulated overall rate of return on rate base of 7.53% or the stipulated rate of return on common equity of 9.70%, or suggesting that the stipulated rates are either unfair or would cause substantial hardship to PSNC's customers. No public witnesses appeared at any of the four public hearings held to receive public testimony.

The lack of substantive evidence of consumer opposition to PSNC's stipulated rate increase does not relieve the Commission of its obligation to reach its own independent conclusion as to whether the Amended Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. Further, even though the record evidence does not establish this fact with respect to any specific PSNC customer, the Commission of its own experience acknowledges and accepts as true the proposition that some percentage of PSNC's customers, particularly those living on fixed

incomes, are economically vulnerable and may struggle to pay an increase in PSNC's rates granted in this docket. Likewise, the Commission must keep this in mind as it undertakes to balance the interests of customers with the constitutional requirements of establishing adequate rates for PSNC.

As noted above, the record evidence in this proceeding supports the legitimacy and reasonableness of the levels of return on rate base and allowed rate of return on common equity reflected in the Amended Stipulation. In light of this fact, the question for the Commission becomes whether the Amended Stipulation represents an appropriate balancing of the interests of customers, the Company, and shareholders, by establishing rates that are as low as may be reasonably consistent with the requirements of due process. As explained below, the Commission concludes, based on its own independent judgment, that the Amended Stipulation satisfies the requirements of North Carolina law in this respect.

First, in his supplemental testimony witness Hevert acknowledges that the stipulated allowed rate of return on common equity of 9.70% is below what he recommended as the range of returns for PSNC. However, witness Hevert indicates that his support for the stipulated ROE is based on the fact that the stipulated ROE represents the give and take among the Stipulating Parties regarding multiple and otherwise contested issues. Finally, he presents a detailed updated review of economic conditions in the State, concludes that these data support his initial conclusion that economic conditions in North Carolina continue to improve, and notes that the changing economic conditions in North Carolina do not impact his recommendations in this case.

It is also significant to note that the direct testimony of PSNC witnesses Addison and Hevert establish without question that PSNC is actively engaged in a significant capital investment program that will continue for the next several years that is driven by federal pipeline safety and integrity requirements and that access to capital on reasonable terms is critical to PSNC in order to fund that investment.

Conclusions on Return

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the utilities which the Commission regulates in that process.

The Commission gives substantial weight to witness Hevert's DCF analysis, particularly on the basis of mean growth rates. Witness Hevert testified that for each of his proxy companies he calculated mean, mean high and mean low results. Based on 30-day, 90-day and 180-day averages, the rate of return on equity range based on

witness Hevert's mean growth rate analysis is from 8.33% to 10.01%. This range provides support for the stipulated rate of return on equity of 9.70%, particularly in light of the Supreme Court's decision in State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast, 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's supplemental testimony in support of the stipulated 9.70% ROE. He testified that although the Stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.0%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on PSNC's determination that the terms of the Amended Stipulation, taken as a whole, are such that PSNC will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost.

The Commission also gives substantial weight to witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates.

The Commission finds it credible that although witness Hevert's three DCF analyses reflect a range of 8.14% to 11.97%, the average of the nine mean DCF results is 9.78%, as can be calculated using the mean results in Table 9a on page 94 of his direct testimony. This average mean of 9.78% is only eight basis points higher than the stipulated 9.70% ROE.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

The Commission also finds credible witness Hevert's testimony that it is his view that on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates, or his recommendation, one way or the other.

In his Brief, the Attorney General contends that even though the stipulated 9.70% ROE appears to move the rate of return gradually toward the lower cost of capital reflected in financial market data, that appearance is deceptive because it ignores the offsetting effect of the higher stipulated equity ratio. The Attorney General further states that the overall rate of return – taking into account the ROE along with other factors proposed in this case – is actually higher at 7.53% than the overall rate of return the Commission fixed for Piedmont three years ago in Docket No. G-9, Sub 631 (which was

7.51%) although Piedmont's ROE was fixed at 10% in that case and capital costs have trended downward. (T5 p 75) Further, the Attorney General states that PSNC appears to be giving customers a lower profit (ROE), but is more than taking it all back by raising the ratemaking equity ratio, absent any showing that PSNC has significantly increased business risk that would warrant such a high equity ratio.

The Commission is not persuaded by the Attorney General's analysis, for two reasons. First, the difference in the Piedmont overall rate of return, 7.51%, and the stipulated overall rate of return, 7.53%, is not significant given the differences in the two utilities and the passage of three years since the Piedmont overall rate of return was established. Secondly, to the extent that comparisons with prior rates are helpful, it is more instructive to note that PSNC's overall rate of return, ROE, and equity ratio will all be significantly lower under the Amended Stipulation than those approved in PSNC's 2008 Rate Order. In the 2008 Rate Order, the approved overall rate of return, ROE, and equity ratio were 8.54%, 10.6% and 54%, respectively. In the present case, the stipulated overall rate of return, ROE, and equity ratio are 7.53%, 9.7% and 52%, respectively.

Consumers pay rates, a charge in cents per therm for the natural gas they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. As the North Carolina Supreme Court has stated:

> The "rate of return" on equity, PSNC's outstanding common stock, "is a percentage that the Commission concludes should be earned on the value of the utility's investment, commonly referred to as the 'rate base.'" Carolina Util. Customers Ass'n, 348 N.C. at 461, 500 S.E.2d at 700. Several variables factor into determining a "just and reasonable" rate of return, including:
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> > (1) The rate base which earns the return; (2) the gross income received by the applicant from its authorized operations; (3) the amount to be deducted for operating expenses, which must include the amount of capital investment currently consumed in rendering the service; and (4) what rate constitutes a just and reasonable rate of return on the predetermined rate base.
>
> Id. at 461-62, 500 S.E.2d at 700.

State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 351 N.C. 223, 232, 524 S.E.2d 10, 17 (2000) (emphasis added).

To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.70%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, PSNC's initial Application requested a $41,583,020 increase in PSNC's annual North Carolina revenues. That revenue increase would require an over-all rate increase of 9.66%. In addition, PSNC requested a 10.6% rate of return on common equity, an 8.14% overall return on a rate base of $949,341,460, and a capital structure that included 53.5% common equity. These are the "big picture" numbers. However, the crucial details of PSNC's general rate Application, as in all general rate cases, are in the hundreds of line items in NCUC Form G-1 that detail the Company's cost of service.

PSNC's Application is supported by substantial and credible evidence that, standing alone, could form the basis of a decision by the Commission to approve a $41,583,020 increase in PSNC's annual North Carolina revenues. However, the details of PSNC's Application, including the cost of service line items, are reviewed by the Public Staff and, in some rate cases, by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Exhibit A, Page 2, of the Amended Stipulation. There are about 40 adjustments, some up and some down. For example, an adjustment reducing PSNC's service company charges by $3,228,865 is made on line 34, and an adjustment adding $91,901 to PSNC's cost of materials and supplies is made on line 9. However, the end result of all the adjustments is a reduction in PSNC's revenue requirement from the requested $41,583,020 to the stipulated amount of $19,054,160. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by PSNC from ratepayers by $22,528,860, including a reduction of approximately $6,000,000 in the return to be paid to equity investors.[14] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Exhibit A further reduce the dollars the investors actually have the opportunity to receive. Thus, while the equity investor's cost was calculated under the terms of the Amended Stipulation by applying a rate of return on equity of 9.70%, instead

[14] Compare Boone Exhibit 6, p. 2, Statement Showing Rates of Return after Adjustments for Proposed Rates, line 3, with Public Staff Late-Filed Exhibit I, Schedule 4, Return on Equity and Original Cost Rate Base, line 3.

of the 10.6% requested in the Application, based in part on existing macroeconomic conditions affecting customers' ability to pay, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.70% rate of return on equity merely because it is lower than the 10.6% requested by PSNC. Rather, it is to emphasize that each of the approximately 40 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.70% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the Carolina Util. Customers Ass'n cases. For example, when the Commission approves, in part due to current economic conditions, a reduction in the investment against which the authorized 9.70% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.70% rate of return on equity.

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Therefore, the Commission cannot, as suggested by the Attorney General, simply conclude that 9.70% "exceeds the ROE that is adequate" for PSNC. Instead, the Commission has incorporated into its analysis all of the myriad factors that make up PSNC's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. Based on that impact and the total effect of the rate order, the Commission concludes that a 9.70% rate of return on equity produces just and reasonable rates for PSNC and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by the evidence.

Based on the above-discussed cost of equity testimony of witness Hevert, the Commission finds his recommendations regarding the appropriate cost of equity for PSNC to be substantial and credible evidence.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as

the resulting customer rates provided for under the Amended Stipulation, are just and reasonable, fair to both PSNC and its customers, and appropriate for use in this proceeding and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering changing economic conditions, and are required in order to allow PSNC, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is set forth in the verified Application, the testimony of the Company's witnesses, and the Amended Stipulation.

The level of adjusted sales and transportation volumes used in the Amended Stipulation is 937,082,412 therms. The sales and transportation throughput volume level is derived as follows:

Sales	491,921,582
Transportation	316,664,980
Special Contract	128,495,850
Total Throughput	937,082,412

The level of purchased gas supply is 499,819,717 therms, and is derived as follows:

Sales	491,921,582
Company Use and Lost & Unaccounted For	7,898,135
Purchased Gas Supply	499,819,717

The throughput level and level of purchased gas supply are the result of negotiations among the Stipulating Parties, as described in the Amended Stipulation, and are not opposed by any party. No other party submitted evidence on the Company's throughput.

The Commission has carefully reviewed the evidence regarding the appropriate throughput level in this docket and concludes that the stipulated throughput levels are a fair and reasonable approximation of the Company's *pro forma* adjusted sales and transportation volumes. The Commission has also carefully reviewed the purchased gas supply level and concludes that it is a fair and reasonable approximation of the Company's *pro forma* purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

The evidence for these findings is contained in the verified Application, the testimony of the Company's witnesses, and the Amended Stipulation.

The test period cost of gas is set forth in Paragraph 7 and Exhibit E to the Amended Stipulation. The amounts shown on Exhibit E to the Amended Stipulation are the result of negotiations among the Stipulating Parties in this docket. The Amended Stipulation reflects the following agreements among the parties regarding PSNC's cost of gas:

Commodity Costs	$110,682,356
Company Use and Lost and Unaccounted For	$1,777,080
Fixed Costs	$67,928,619
Total Cost of Gas	$180,388,055

The stipulated cost of gas is not contested by any party to this proceeding. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the *pro forma* cost of gas, and concludes that the stipulated cost of gas is reasonable and appropriate for use in this docket.

Under the Commission's procedures for truing-up fixed gas costs in proceedings under Commission Rule R1-17(k), it is necessary and appropriate to determine the amount of fixed gas costs that are embedded in the rates approved herein. In the Amended Stipulation, the Stipulating Parties agree that for the purpose of this proceeding and future proceedings under Commission Rule R1-17(k) during the effective period of rates approved in this proceeding, the appropriate amount of fixed gas costs to be allocated to each rate schedule is as set forth in Exhibit C to the Amended Stipulation. No party contests this allocation and no other party submitted evidence supporting a different allocation.

The Commission has carefully examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are fair and reasonable.

Under the Commission's procedures for establishing rates and truing-up commodity gas costs, it is necessary to establish a Benchmark Commodity Cost of Gas (Benchmark) embedded in sales customer rates. The Amended Stipulation provides that in establishing rates for this proceeding, the parties have agreed to use PSNC's current Benchmark of $0.225 per therm subject to any filed changes in such rate prior to implementation of revised rates in accordance with the Commission's final order in this docket. No party contests the use of a $0.225 per therm Benchmark in establishing rates for this proceeding and no other party submitted evidence on this issue. The

Commission has carefully examined this proposal and concludes that the use of a $0.225 per therm Benchmark for purposes of establishing rates in this proceeding is fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding is contained in the Amended Stipulation, as supported by the direct and supplemental testimony of Company witness Paton and the testimony and revised exhibits of Public Staff witness Larsen.

The stipulated rate design and rates, necessary and appropriate to provide PSNC a reasonable opportunity to recover the stipulated revenue requirement in this docket, are reflected in Exhibit B to the Amended Stipulation. On Exhibit B, PSNC has included a new Medium General Service rate schedule 140 (MGS Rate 140) applicable to commercial and small industrial customers who use more than 25,000 but less than 60,000 therms per year. According to witness Paton, the larger customers who will move to MGS Rate 140 will no longer distort the average usage levels for the Small General Service Rate 125. Witness Larsen agreed with the Company's reasoning for creating the MGS Rate 140 and recommended that it be approved.

In addition, Exhibit B to the Amended Stipulation reflects that the Stipulating Parties have agreed to an additional usage tier for Rate Schedule 175. The additional usage tier for Rate 175 is also shown on Public Staff witness Larsen's Amended Exhibit C, page 2 of 2. The Stipulating Parties agreed that the additional usage tier will not result in any revenue shifting between rate classes.

The computations on Exhibit B show that the proposed rates will produce the revenues calculated under the rate design, as well as the proposed gas costs rates approved for use in this proceeding. The Commission has carefully reviewed these rates, as well as all record evidence relating to the proper rates to be implemented in this proceeding, and concludes that the stipulated rates are just and reasonable.

A portion of the rate increase will be recovered through the increase in reconnect fees. At the evidentiary hearing, Public Staff witness Larsen testified that the proposed reconnect fee of $80 for residential customers during regular working hours was justified. During questions from the Commission, witness Larsen stated that the Public Staff requested justification of the increase in a data request sent to the Company, and PSNC responded that the increase reflected an annual inflation adjustment since 2006 of approximately two percent per year. Witness Larsen further testified that there was an in-depth analysis performed a number of years ago where all of the components of the cost of reconnecting gas service were analyzed. Witness Larsen cited the various steps and tasks involved in this process. Witness Larsen stated that, in today's dollars, the result is it costs almost $100 for a reconnect. He testified that customers avoid paying the monthly facilities charge while they are disconnected. Witness Larsen concluded that $80 was reasonable and did not exceed the cost that the Company had to incur to provide that service.

The Commission has carefully reviewed the cost components of the reconnection process and concludes that the proposed reconnect fees proposed by PSNC and agreed upon by the Stipulating Parties are fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding is contained in the Application, the direct testimony of Company witness Ratchford, the direct and supplemental testimony of Company witness Paton, the direct testimony of Public Staff witness Perry, the Amended Stipulation, and Rider E of the Company's tariffs.

In its Application, PSNC indicated that it was incurring substantial and ongoing capital expenses associated with efforts to comply with federal pipeline safety and integrity management requirements. In order to address the magnitude and impact of its capital investments required to comply with federal pipeline safety and integrity requirements on a going-forward basis, and as authorized by G.S. 62-133.7A, PSNC proposed the adoption of an IMT mechanism in its tariffs. According to PSNC, this mechanism would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than they would be if PSNC had to wait for a general rate case.

In his direct testimony, Company witness Ratchford testified to the Company's ongoing capital investments driven by compliance with federal pipeline safety and integrity requirements and emphasized the importance of pipeline safety to the Company, its customers, and the public in general. Witness Ratchford set out a detailed description of the federal Transportation Integrity Management Plan (TIMP) and Distribution Integrity Management Plan (DIMP) processes required of the Company. He also described in some detail the Company's evolving techniques and efforts to comply with TIMP and DIMP requirements as well as the Company's future planned compliance activities. In his testimony, witness Ratchford described the nature of TIMP and DIMP compliance activities and the fact that federal regulation was an actively evolving process that could generate substantial additional compliance requirements in the future and that the full scope of those requirements could not be known at this time. Witness Ratchford also explained that the IMT mechanism proposed by the Company to track these costs would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than if PSNC were required to wait for a general rate case. He explained that, in this way, the Company's customers are not subjected to a large, one-time rate increase, and the amount of the increase is reduced by minimizing debt expense on the capital necessary to make integrity management improvements, as well as minimizing general rate cases and their associated expenses.

In her direct testimony, witness Paton explained the Company's proposed IMT mechanism and provided a proposed form of such tracker in Paton Exhibit 4.

Witness Paton testified that in broad terms, the IMT provides for PSNC to adjust its rates biannually in order to recover the revenue requirement associated with Integrity Management Plant Investment and associated costs incurred by PSNC resulting from

prevailing federal standards for pipeline integrity and safety that are not otherwise included in current base rates.

Public Staff witness Perry testified that after several months of discussions, PSNC and the Public Staff agreed to a modified form of the IMT mechanism filed by the Company. Witness Perry stated that the IMT mechanism will assist PSNC in the implementation and timely recovery of costs associated with its investment of capital in compliance with the requirements of federal and state laws and regulations regarding pipeline integrity (including both transmission and distribution integrity), reliability and safety.

Witness Perry testified that the Public Staff has had approximately 2 ½ years of experience auditing the Piedmont Natural Gas, Inc. IMR mechanism.[15] This experience was very helpful in discussions with PSNC regarding its proposed IMT. The Amended Stipulation includes a provision that sets out how to determine excluded costs from the Company's Integrity Management Plant Investment using both the exclusion percentages based on PSNC's budgeted integrity management (IM) projects, as well as the direct assignment approach for specific IM projects that have a significant non-IM component. Witness Perry testified that the Public Staff and PSNC agreed that the excluded reasonable and prudent costs shall be eligible for inclusion in recoverable rate base in PSNC's next general rate case proceeding.

The Amended Stipulation further stated that the Stipulating Parties agreed that costs incurred for system expansion/improvement or routine maintenance, repair and replacement of system components that are not required to comply with federal gas pipeline safety requirements shall not be included in amounts recovered under the IMT mechanism.

Witness Perry also stated that the Public Staff and PSNC worked hard to determine a fair and reasonable approach to enable the Company to recover its prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements.

No other party submitted evidence on the issue of the proposed IMT mechanism.

In the Attorney General's Brief, the Attorney General states several concerns about the proposed IMT. In summary, the Attorney General acknowledges that the legislature authorized the Commission in G.S. 62-133.7A to adopt a rate adjustment mechanism to allow the recovery of prudent costs of compliance with federal pipeline safety requirements. Nevertheless, the Attorney General contends that the IMT is not in the public interest because PSNC has not shown that there is a need for such rate adjustment mechanism, and any benefit it offers to investors is outweighed by disadvantages to consumers, such as frequent additional rate increases, an expedited

[15] See Order Approving Partial Rate Increase and Allowing Integrity Management Rider (G-9, Sub 631, December 17, 2013); and Order Approving Stipulation (G-9, Sub 631, November 23, 2015).

review, no regard for offsetting cost factors, and a lack of meaningful public input. The Attorney General further contends, based on testimony by PSNC witness Addison, that the IMT is not needed to address investor concerns about timely recovery of capital costs.

In its Reply Brief, PSNC takes issue with the Attorney General's interpretation of witness Addison's testimony regarding investor concerns. PSNC submits that the Commission's rejection of the IMT would be viewed by investors as a sign of an unsupportive regulatory environment, particularly when the IMT is a part of a near-unanimous settlement.

The Commission has carefully considered the evidence in this proceeding related to the proposed IMT mechanism, as well as the Attorney General's concerns, and has reached the following conclusions. First, the Commission concludes that the form of IMT mechanism attached in Exhibit H to the Amended Stipulation falls within the scope of G.S. 62-133.7A. That statute authorizes the Commission to adopt "a rate adjustment mechanism to enable the company to recover the prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return." In this case, the proposed form of IMT attached to the Amended Stipulation provides for the recovery of return, taxes, and depreciation on capital investment associated with federal gas pipeline safety requirements in a manner consistent with the statute and in the same fundamental manner that PSNC is permitted to recover those items of its cost of service in a general rate case proceeding. This approach to IM cost recovery is reasonable and consistent with statutory requirements and normal regulatory practices.

Second, the Commission concludes that the IMT mechanism proposed for adoption and implementation in the Amended Stipulation is beneficial to customers because it provides for the use of both the exclusion percentages determined using PSNC's budgeted IM projects, as well as the direct assignment approach for specific projects that have a significant non-IM component.

Third, the proposed IMT Rider expressly provides for Commission review of the mechanism at the earlier of PSNC's next general rate case proceeding or four years from the implementation of the mechanism and also specifically grants any party the right to apply to the Commission to terminate or modify the mechanism at any time on the grounds that the rider mechanism, as approved by the Commission, is no longer in the public interest.

Fourth, consistent with the requirements of G.S. 62-133.7A, the Commission concludes that adoption and implementation of the IMT mechanism as reflected in Rider E of the Company's tariffs and attached to the Amended Stipulation as Exhibit H is in the public interest. The Commission finds the uncontested evidence of PSNC's required capital expenditures on TIMP/DIMP compliance convincing. It is equally persuaded that regular and repeated general rate case proceedings, otherwise necessary to reflect such investments in PSNC's rate base, would be a detriment to PSNC and its customers, and would serve no purpose other than to increase regulatory

costs paid by ratepayers and the regulatory burden on all parties who participate in PSNC's general rate proceedings. The Commission recognizes, as the Attorney General points out, that separately accounting for TIMP/DIMP compliance costs and addressing them through the IMT mechanism on an intra-rate case basis effectively isolates those costs from other aspects of PSNC's cost of service. The Commission is satisfied that the public interest is protected from any potentially adverse impacts from such treatment through a variety of means, including the limited nature of the costs recoverable through the mechanism, using the exclusion percentages determined using PSNC's budgeted IM projects, as well as the direct assignment approach for specific IM projects, the special contract crediting provision contained therein, the mandatory and permissive review provisions contained in the rider, and the Commission's general and continuing oversight of the Company's earnings. The Commission also concludes that the tracker provides an overall benefit to customers since it would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than if PSNC were required to wait for a general rate case, and therefore avoids subjecting the Company's customers to a large, one-time rate increase. In addition, the amount of the increase is reduced by minimizing debt expense on the capital necessary to make integrity management improvements, as well as minimizing general rate cases and their associated expenses. Further, the tracker is subject to Commission review after four years.

With respect to the Attorney General's concerns about the expedited nature of the review process and ensuring meaningful public input, the Commission is not persuaded that the expedited procedure is a detriment to the Commission's decision-making process, or that there will be a lack of opportunity for meaningful public input. As Public Staff witness Perry testified, the Public Staff has about 2 ½ years of experience auditing the Piedmont Natural Gas, Inc., IMR mechanism. Similarly, the Commission has that same level of experience in reviewing the evidence and making decisions regarding the proper implementation of Piedmont's IMR. Further, the Commission is not aware of any complaints from parties to the Piedmont IMR dockets or the public that the semi-annual reviews have not afforded interested persons a full and fair opportunity to be heard. In addition, if the Commission receives such complaints with regard to its reviews of PSNC's IMT, the Commission has the authority and the procedural tools to remedy those concerns.

Finally, the Commission believes that implementation of the proposed IMT mechanism will promote public safety by supporting the timely recovery of costs associated with pipeline safety and integrity expenditures by the Company. Safety and reliability of utility infrastructure is of critical importance to the State and the Commission, and this mechanism facilitates the accomplishment of that goal.

Based on the foregoing, and in the absence of any evidence to the contrary, the Commission finds the Integrity Management Tracker mechanism as reflected in Rider E of the Company's tariffs and described in Paragraph 10 and attached as Exhibit H to the Amended Stipulation to be just, fair, reasonable, in the public interest, and appropriate for adoption in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding is contained in the Amended Stipulation reflected in Paragraph 6 and Late Filed Exhibit D.

Under PSNC's CUT mechanism, certain baseload and heat factors, as well as "R" values, are needed in order to make the calculations periodically required under that mechanism. The Stipulating Parties have provided updated factors in this proceeding as reflected in Paragraph 6 and Late Filed Exhibit D of the Amended Stipulation. These values are not contested by any party and no other party has offered evidence supporting other factors. Based on the Amended Stipulation, and the entire record of evidence in this proceeding, the Commission finds and concludes that the updated CUT factors, including the "R" values, identified on Late Filed Exhibit D to the Amended Stipulation are reasonable and appropriate and should, therefore, be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence for this finding is contained in the Company's initial filing and the Amended Stipulation.

In PSNC's Application, supported by the direct testimony of Company witness Boone, the Company proposed to amortize and recover a number of previously deferred regulatory assets including PIM and manufactured gas plant (MGP) O&M costs. It also proposed to amortize and recover DIMP O&M costs. In Paragraph 5 of the Amended Stipulation, the Stipulating Parties propose certain agreed upon changes to the Company's proposed amortizations and recovery of PIM, MGP, and DIMP O&M costs. The Stipulating Parties support the five year amortization periods set forth in Paragraph 5 of the Stipulation and the ongoing interim deferral mechanism for PIM and DIMP O&M costs. No party has opposed the proposals contained in Paragraph 5 of the Amended Stipulation and no other evidence has been submitted regarding these issues.

The Commission has carefully considered the proposed amortization periods and related matters set forth in Paragraph 5 of the Amended Stipulation, as well as all record evidence on the amortization of these regulatory assets, and concludes that the stipulated amortization treatment and specified amortization periods are consistent with the Commission's prior treatment of similar costs and are otherwise fair and reasonable and should be approved. The Commission further concludes that the proposed continuation of the existing regulatory asset treatment for ongoing PIM and DIMP O&M costs is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence for this finding is contained in the North Carolina General Statutes, the Amended Stipulation, the supplemental testimony of Company witness Paton, and the testimony of Public Staff witness Boswell.

North Carolina Session Law 2015-241 established a prospective downward adjustment in the North Carolina corporate income tax rates to be effective for tax year 2017. The Amended Stipulation states that PSNC will make downward adjustments to its rates to recognize the reduction in the state corporate income tax rate to 3% beginning January 1, 2017. In the Amended Stipulation, the Stipulating Parties further agreed to work together on determining the appropriate revenue requirement reduction and effectuating such reductions and to file notice of such rate reductions with the Commission prior to implementation. No party opposed this plan to adjust PSNC's rates for reductions in income tax expense and no other evidence on this issue was presented to the Commission in this docket.

The Commission has considered the proposed adjustment to corporate income tax set forth in Paragraph 8 of the Amended Stipulation, as well as all evidence of record regarding the corporate tax changes effectuated by North Carolina Session Law 2015-241, and concludes that the stipulated treatment is consistent with the Commission's prior treatment of other tax reductions and is otherwise fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding is set forth in the direct testimony of Company witnesses Spanos and Boone, the testimony of Public Staff witness Boswell, and in the Amended Stipulation.

In the Amended Stipulation, the Stipulating Parties agreed that the revised depreciation rates, as presented in the deprecation study filed along with and supported by Company witness Spanos' direct testimony, should be implemented effective January 1, 2017. Public Staff witness Boswell testified that the Public Staff reviewed the depreciation study, found no issues with the new depreciation rates, and recommends approval of the proposed depreciation rates. No party contested the implementation of PSNC's revised depreciation rates as proposed in the Amended Stipulation and no other party submitted any additional evidence on this issue.

Based on the direct testimony of Company witnesses Spanos and Boone and the Amended Stipulation, the Commission concludes that implementation of the revised depreciation rates filed in the instant docket, effective January 1, 2017, as proposed in the Amended Stipulation, is just and reasonable and should be approved for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence for this finding is contained in the direct testimony of Company witnesses Paton and Jackson and the Amended Stipulation.

Company witnesses Paton and Jackson testified to proposed additional changes in the Company's tariffs and service regulations and the reasons underlying those changes. Witness Paton testified that minor changes were made to PSNC's rate schedules, including: (1) adding language stating that the rate schedules are subject to the Integrity Management Tracker; (2) adding language to the Large General Service and transportation rate schedules to indicate a change in billing to state the customer's consumption on the basis of dekatherms rather than therms; and (3) other minor changes as noted on Paton Exhibit 4.

With regard to changes to PSNC's service regulations, witness Paton testified that the Company is proposing several minor changes, including: (1) deleting current Section 29, which addresses the methodology for determining rate service priority pursuant to Commission Rules R6-12 and R6-19.2, and providing this information in a new Rider B to the tariff; (2) adding a provision allowing reclassification of a customer outside of the annual review period under certain circumstances; (3) adding language in Section 21 regarding gas quality and measurement; and (4) adding new Section 29 to clarify the customer's responsibility for paying certain taxes. Witness Paton further stated that PSNC is proposing other minor changes to its riders for clarification, formatting and grammatical corrections.

Witness Paton also testified regarding proposed additional language in Section 21 to address gas quality and measurement. With respect to gas quality, the language in Section 21 assumes that all gas will be delivered by an interstate pipeline and will be, "subject to the quality specifications of the interstate transporter's Federal Energy Regulatory Commission-approved contract." The Commission asked what would happen if gas was produced in North Carolina and put into PSNC's system. Witness Paton responded that she didn't know that the Company, "contemplated anything above and beyond what's coming off the interstate now." (T Vol. 6, p. 121) Witness Jackson responded that the Company had been contacted about biogas projects over the past few years and had contemplated installing a chromatograph at the site where the supply source would come into PSNC's system. When asked whether PSNC would have responsibility for the quality of biogas it accepts, witness Jackson responded that "The producer is required to meet the gas quality standard so that our customers will not be impacted." (T Vol. 6, p. 166) No party objected to the adoption of the proposed language in Section 21 dealing with gas quality. The Commission notes that, should parties seek to place gas into PSNC's system from a North Carolina location, it could be necessary to clarify and amend this section. Further, the language in this Section should not be seen as intended to bar or hinder the development of gas supplies in North Carolina.

With regard to the use of a weighted average BTU content of gas entering PSNC's system, the Commission asked about differences in heat content from different sources of supply. Witness Paton responded that, in the past, PSNC used only one BTU reading, but now that the Company has gas coming from different directions, a weighted average of the BTU content of the gas at different take-off stations is used. Witness Paton added that the difference has not been significant. When asked how much variance would be acceptable, she responded that the use of a system–wide average BTU factor "would balance out any of the pricing concerns." (T Vol. 6, p. 123) No party objected to the adoption of the proposed language in Section 21 dealing with the measurement of gas and the conversion from cubic feet to therms or dekatherms using a weighted average BTU content.

Witness Jackson testified that PSNC reviewed its tariffs and guidelines governing interruptible service following the failure of numerous customers to curtail their usage during an unusually cold period in January 2014. She testified that PSNC is recommending changes in those tariffs and guidelines to improve the Company's ability to serve its firm customers in the event of a curtailment. Regarding proposed changes to Rider A, Curtailment of Service under Commission Rule R6-19.2 and Emergency Services, witness Jackson testified to the following changes: (1) elimination of on-peak emergency service, resulting in one level of emergency service with a single assessment rate; (2) an increase in the assessment rate for Unauthorized Gas from $2.50 per therm to $5.00 per therm, or $50.00 per dekatherm; and (3) removal of the allowance of 10 therms per day for pilot usage, and modification of the rider to allow a maximum of 10 dekatherms per day in Emergency service without prior authorization from PSNC. Witness Jackson testified that these changes will be more effective in deterring noncompliance with curtailment, and more efficient for the Company to administer.

Witness Jackson further testified to two changes being made to PSNC's interruptible Rate Schedules 150, 160, 165 and 180. The first change requires customers to provide and update contact information for two authorized representatives. The second change adds language describing some of the costs, not addressed in Rider A, that a customer may incur for taking Unauthorized Gas during a curtailment event. Witness Jackson described a third change, needed only for Rate Schedule 180, to clarify that non-compliance with a curtailment order may result in PSNC valving off the customer's gas service. Witness Jackson stated that PSNC is proposing these changes to make the curtailment process more effective and efficient.

Finally, witness Jackson described several changes to PSNC's Transportation Pooling Agreement designed to improve the transportation nomination process and encourage poolers to maintain balance in their deliveries of gas to PSNC's system.

Company witness Paton filed Exhibit 4 with her direct testimony. Exhibit 4 includes the Company's proposed tariffs, Rules and Regulations and Transportation Pooling Agreement. For the most part, the Stipulating Parties accepted the tariffs, Rules and Regulations as filed in Paton Exhibit 4. However, the Stipulating Parties made changes to

Riders C and E, and the Transportation Pooling Agreement. Those changes are reflected in Exhibit H to the Amended Stipulation. No party objected to these changes.

The Commission has carefully reviewed these changes to the Company's service regulations, tariffs, riders and the Transportation Pooling Agreement. The Commission finds and concludes that they are just, fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence for this finding is contained in the Application, the direct testimony of Company witness Paton, and the Amended Stipulation.

In its Application, PSNC proposed to refund over a one-year period the EDIT as set forth in Paton Exhibit 13. In the Amended Stipulation, the Stipulating Parties agreed, in Paragraph 12, that it was appropriate to implement a temporary decrement in rates to refund the EDIT as set forth in Paton Exhibit 13 over a one year period. The parties also agreed that in accordance with North Carolina Session Law 2013-316 (House Bill 998), PSNC will refund the additional EDIT over a one-year period, and any amount remaining after twelve months shall be transferred to the All Customers' Deferred Account. No party has contested the refund of EDIT as proposed in the Application and agreed to in the Amended Stipulation, and no other party has presented any additional evidence on this issue.

The Commission has carefully considered the refund of EDIT as proposed in the Amended Stipulation, as well as all of the evidence in the record, and concludes that it is fair and reasonable and should be approved. The Commission further finds that any amount of EDIT remaining after twelve months should be transferred to the All Customers' Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding is contained in the Amended Stipulation.

In Paragraph 13 of the Amended Stipulation, the Stipulating Parties proposed to continue funding of conservation programs at a level of $750,000 per year, as reflected in test year operating expenses. No party contested the continued level of conservation spending or recovery of conservation dollars provided in the Amended Stipulation.

The Commission has carefully considered the proposed continuous level and treatment of conservation funding in the Amended Stipulation and finds it to be fair and reasonable. As a general statement, the Commission believes that energy conservation and efficiency serve the public interest and that conservation measures provide long-term and year-round benefits to PSNC's customers and to the public as a whole.

Based on the foregoing, the Commission concludes that the amount of conservation spending provided for by the Amended Stipulation, and the recovery of those costs through rates, is appropriate for this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence for this finding is contained in the Application, the direct testimony of Company witness Ratchford, the Amended Stipulation, Public Staff Late-Filed Exhibit I, and the direct testimony of Public Staff witness Boswell.

In its Application, PSNC proposed to include in its cost of service in this proceeding $275,000 for the funding of GTI research into natural gas pipeline safety and reliability. In his direct testimony, Company witness Ratchford indicated that the Company's proposal to include a contribution to GTI in this case was targeted at GTI's Operations Technology Development (OTD) initiative. Witness Ratchford described the OTD initiative as a program specifically targeted towards developing tools and technologies that will assist local distribution companies such as PSNC in meeting the requirements associated with their TIMP and DIMP.

In Public Staff Late-Filed Exhibit I, witness Boswell demonstrated that PSNC's proposal of $275,000 for the funding of GTI was based on an estimate of the number of meters as of December 31, 2016, multiplied by $0.50 per meter. The Amended Stipulation reflects a downward adjustment to the actual number of meters on June 30, 2016, found in Public Staff Late-Filed Exhibit I.

In the Amended Stipulation, the Stipulating Parties agreed, in Paragraph 14, "that the Company may fund research and development activities through annual payments to GTI that have been included in operating expenses in this proceeding."

No party has contested the funding of GTI proposed in the Application and agreed to in the Amended Stipulation and no other party has presented evidence on this issue.

The Commission has carefully considered the GTI funding proposed in the Amended Stipulation, and concludes that the funding of GTI at the level of $268,631 per year to support the development of new technologies, practices and processes which enhance the safety and reliability of natural gas transmission systems is in the public interest and is also fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 – 35

The evidence supporting these findings is contained in the testimony and exhibits of the Company and Public Staff, and in the Amended Stipulation.

In PSNC's last general rate case in Docket No. G-5, Sub 495, the Stipulating Parties agreed that the appropriate Allowance for Funds Used During Construction

(AFUDC) rate for the Company should be the overall rate of return, adjusted for income taxes. In that docket, Company witness Paton testified in response to a question from the Commission that the AFUDC rate would remain in effect until the Company's next general rate case proceeding, which is the docket now before the Commission. The Stipulating Parties in this docket agreed to continue using the overall rate of return, adjusted for income taxes. The Commission finds that the continued use of the overall rate of return for the AFUDC rate, adjusted for income taxes, is just, reasonable and appropriate and should be approved.

PSNC has been applying the statutory maximum of 10% authorized in G.S. 62-130(e) to balances in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The Stipulating Parties agreed in the Amended Stipulation that beginning with the month in which the Order is issued, PSNC will use an interest rate of 6.6% per annum as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by PSNC for the accrual of interest on the Deferred Gas Cost Accounts will remain unchanged.

In response to a question from the Commission, PSNC witness Paton stated that the 6.6% is also applied to the balances in the Customer Utilization Tracker (Rider C) and the Integrity Management Tracker (Rider E). Those two riders explicitly call for a reevaluation of the rate every year, and witness Paton confirmed that the 6.6% rate applied to Deferred Gas Cost Accounts would also be reevaluated annually.

The Commission finds that a reduction in the interest rate applied to the balances in the Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts with the rate to be reevaluated annually is just, reasonable and appropriate and should be approved.

Public Staff witness Perry testified that the Stipulating Parties agreed to changes in certain PSNC reporting requirements including filing the GS-1 Report in a format similar to the ES-1 filed by the electric utilities, effective with filings after January 1, 2017. No party opposed this change, which is administrative in nature. The Commission finds that requiring PSNC to file its GS-1 report in a format similar to the ES-1 filed by the electric utilities is reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding is contained in the hearing testimony of Company witness Addison.

The Commission questioned PSNC witness Addison about PSNC's participation in the SCANA Utility Money Pool (UMP). It was noted that the monthly reports provided by PSNC to the Commission in Docket No. G-5, Sub 484 disclosed a distinctive trend of PSNC being far more often a lender than a borrower in its UMP transactions, and

generally lending far more than it has borrowed. Witness Addison was asked what benefits he saw PSNC receiving from its participation in the SCANA UMP.

He responded that “The Pool is set up so that the different Companies can take advantage of each other’s cash flow or investment abilities at different points in time.” Witness Addison testified that PSNC is “moving back into that period where they’re going to be a net borrower.” (T Vol. 5, p. 117) However, he also testified that:

> PSNC has not had as much capital to invest in the business as it does prospectively, so we've not had to issue a great deal of long-term debt, anything like that, not been into the commercial paper markets a lot in the past. That has changed now and so now PSNC is a net borrower just like SCE&G is. (T Vol. 5, p. 117)

Witness Addison further testified that the UMP has allowed PSNC to earn some return when it has had excess cash. He stated that participation in the UMP is a prudent and efficient use of PSNC's capital. He pointed out that SCANA could have altered its dividend policies, and moved more PSNC cash to SCANA, “but we wanted to keep that capital structure, maintain those credit ratings at PSNC, so we've kept the dividend payouts ratio very similar over the period of time.” (T Vol. 5, p. 118)

To help the Commission monitor PSNC’s activity in the SCANA UMP, the Commission finds good cause to require PSNC to add to the information provided in its monthly UMP report filed in Docket No. G-5, Sub 484. Beginning with the January 2017 report, PSNC shall report the net daily balance of loans and receipts, and the total net interest amount on the balances. This information will be provided for the month, and for the calendar year to date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact is contained in the consumer statements of position received by the Commission, the Public Staff and the Attorney General. The following is a summary of these statements.

Bruce Sampsell, from Chapel Hill, submitted a consumer statement of position to the Public Staff stating that for the past 15 years the returns on equity for both gas and electric utilities have been declining. He provided an economic analysis and other documentation. He further noted that there is absolutely no sound rationale to support PSNC’s request for a 10.6% ROE. Mr. Sampsell urged the Public Staff to carefully review his submissions as it considers what rate increases and authorized ROE percentage are justified in this circumstance.

Marie Christy, from Kannapolis, submitted a consumer statement of position to the Attorney General’s office stating that she lives by herself on a fixed income. She stated that gas prices have come down all over the nation, but not for heating gas. Ms. Christy stated that she will soon be 75 years old and lives alone. Her only income is

from Social Security. She said she bundles up and keeps her heat low, but still the bills are high.

Bill Raleigh submitted a consumer statement of position by email to the Commission stating that he recently received notification from PSNC of a proposed increase in residential gas pricing. He stated that in 2008, wellhead pricing for gas was just short of $8.00 per thousand cubic feet (tcf) and today it is $3.00 per tcf. The increase requested is supposedly for infrastructure improvements. With the price of gas dropping since 2008 he questions why that increase in operating income was not used for the improvements and why is it needed now if we have been able to exist since 2008. Based on the above and other noted considerations, he does not believe an increase is warranted at this time.

Diana Asbury submitted a consumer statement of position by email to the Commission stating that she seeks help on behalf of those on a limited/fixed income, herself included, for the 9.7% rate increase requested by PSNC. She acknowledges that rate increases are a way of life, but the requested percentage is too high for the senior community. The extra $3.41 per month that bills would increase may not sound like a lot but to the senior community, it could mean a loaf of bread or a container of milk. She stated that for those on a limited/fixed income who are having difficulties making ends meet any increase causes a hardship.

The Commission is aware that some areas of the state, including portions of PSNC's service territory, continue to have significant levels of unemployment and include significant numbers of low-income customers. As a result, the Commission has fully considered the negative impacts of the proposed rate increase on PSNC's customers and weighed those against PSNC's need to remain financially sound so that the Company is able to continue providing all of its customers safe, adequate and reliable natural gas service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 38

The evidence supporting this finding of fact is contained in the testimony and exhibits of the Company and Public Staff, and in the Amended Stipulation.

As fully discussed above, the provisions of the Amended Stipulation are the product of the give-and-take of settlement negotiations between PSNC, the Public Staff, CUCA, and Evergreen. Comparing the Amended Stipulation to PSNC's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Amended Stipulation that are more important to PSNC, and, likewise, there are provisions that are more important to the Public Staff. For example, PSNC is intent on obtaining approval for the IMT, which it views as imperative to a fair recovery of its costs of pipeline safety. On the other hand, the Public Staff is intent on limiting the IMT recovery to those costs directly related to pipeline safety, as indicated by the restrictions placed on the IMT in Paragraph 10.B. of the Amended Stipulation

The end result is that the Amended Stipulation strikes a fair balance between the interests of PSNC and its customers. As discussed above, the Commission has fully evaluated the provisions of the Amended Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Amended Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. Therefore, the Commission approves the Amended Stipulation in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

The evidence for this finding of fact is contained in the Application, the testimony and exhibits of the PSNC and Public Staff witnesses, and the record as a whole.

Pursuant to G.S. 62-30, et seq., the Commission is required to set just and reasonable rates for North Carolina's regulated public utilities. In summary, under G.S. 62-133(a) the Commission is required to set rates that are “fair both to the public utilities and to the consumer.” In order to strike this balance between the utility and its customers, the two most important factors the Commission considers are (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b).

PSNC's continued operation as a safe and reliable source of natural gas for its customers is vitally important to PSNC's individual customers, as well as to the community and business entities served by PSNC, and the economy in general. PSNC presented credible and substantial evidence of its need for increased capital investment to, among other things, meet the requirements of pipeline safety laws, expand and upgrade its pipeline and other infrastructure to serve new customers, and expand the use of technology to more efficiently serve its customers.

For example, PSNC witness Harris testified that the Company has strengthened its pipeline safety efforts in response to the federal Pipeline and Hazardous Materials Safety Administration's (PHMSA's) transmission and distribution pipeline safety regulations. Witness Harris stated that the PHMSA regulations place a great deal of responsibility on PSNC, and are complex, costly and subject to continued change.

In addition, witness Harris testified that since 2008 PSNC has added 77,025 customers, 1,424 miles of transmission and distribution mains, and 83,866 service lines. He also described significant system improvements made by PSNC, such as new compressor stations, and new transmission and high-pressure distribution pipelines.

Further, witness Harris testified that since 2008 PSNC has completed the conversion to automated meter reading, and enhanced its computer-aided dispatch system to enable service calls to be routed more efficiently. Witness Harris also testified

that PSNC has 154 vehicles that operate on compressed natural gas (CNG), and that in 2015 alone the Company saved more than $300,000 by using CNG, compared to the cost of using gasoline and diesel fuel.

These are representative examples of the capital investments made by PSNC since its last rate case in order to continue providing safe and efficient service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of PSNC's customers in receiving safe, adequate and reliable natural gas service at the lowest possible rates, and the interests of PSNC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Amended Stipulation is hereby approved in its entirety.

2. That the Company is hereby authorized to adjust its rates and charges in accordance with the Amended Stipulation and this Order (as such rates may be adjusted for any changes in the Benchmark, and changes in Demand and Storage Charges prior to the effective date of the revised rates) effective for service rendered on and after November 1, 2016.

3. That the Company is authorized to implement the Integrity Management Tracker as described in Paragraph 10 of the Amended Stipulation and Rider E to the Company’s tariffs.

4. That the Company is authorized to implement the changes to its Rate Schedules and Service Regulations contained in Paton Exhibit 4 and attached to the Amended Stipulation as Exhibit H for periods effective on and after November 1, 2016.

5. That the Company shall file clean versions of the new and revised tariffs and service regulations to comply with this Order within five (5) days from the date of this Order. Rider E of such filing shall include the appropriate percentages for Section III.(f) and Section IV.(b).

6. That in the true-up of fixed gas costs for periods subsequent to November 1, 2016, in proceedings under Commission Rule R1-17(k), the Company shall use the fixed gas costs allocations set forth in Exhibit C to the Amended Stipulation.

7. That the Customer Usage Tracker mechanism factors set forth on Late-Filed Exhibit D to the Amended Stipulation are approved for use in the implementation of the provisions of that mechanism subsequent to November 1, 2016.

8. That the Company shall refund the EDIT as set forth in Paragraph 12 of the Amended Stipulation, and any balance that remains at the end of twelve months shall be transferred to the All Customers' Deferred Account.

9. That for quarters ending after the effective date of the Order in this docket, the Company shall begin utilizing a revised NCUC GS-1 Earnings Surveillance Report format that is similar to the format of ES-1 Earnings Surveillance Report that is submitted to the Commission by the electric utilities.

10. That beginning November 1, 2016, the Company shall use 6.60% as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by the Company for the accrual of interest on the Deferred Gas Cost Accounts shall remain unchanged.

11. That beginning with its January 2017 UMP monthly report in Docket No. G-5, Sub 484, regarding the SCANA Utility Money Pool, PSNC shall report the net daily balance of loans and receipts, and the total net interest amount. This information shall be provided for the month, and for the calendar year to date.

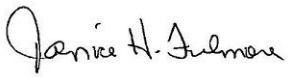
12. That the Company is authorized to implement the other actions, practices, principles, and methods agreed upon in the Amended Stipulation.

13. That the Company shall send the notice attached hereto as Attachment A to its customers beginning with the billing cycle that includes the rate changes approved herein.

ISSUED BY ORDER OF THE COMMISSION.

This the __28th__ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION



Janice H. Fulmore, Deputy Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-5, SUB 565

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company	)	
of North Carolina, Inc. for a General	)	PUBLIC NOTICE
Increase in its Rates and Charges	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) issued an Order allowing Public Service Company of North Carolina, Inc. (PSNC or the Company) to increase its rates and charges by approximately $19 million annually, or 4.39% overall, effective for service rendered on and after November 1, 2016.

On March 31, 2016, PSNC filed an application seeking a general increase in its rates and charges, implementation of a new Integrity Management Tracker mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, and proposed funding for gas distribution research activities conducted by the Gas Technology Institute (GTI).

In its application, the Company requested an increase of approximately $41.6 million annually. The Company stated that the rate increase was needed because it has, since its last general rate case in 2008, greatly expanded natural gas service in its rapidly growing service area by making significant capital improvements to its system, and has invested substantial additional capital in order to comply with federal environmental and pipeline safety and integrity regulations and requirements. In support of its request for a rate increase, the Company explained that the increase is necessary in order to allow PSNC to access capital markets on reasonable terms, earn a fair return on its investment, and allow the Company to continue investing in the growth, safety, and reliability of its system.

The increase approved by the Commission was the result of a stipulation (Stipulation) entered into between the Company and other parties to the proceeding, including the Public Staff – North Carolina Utilities Commission. The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service.

Overall, the Commission has approved a residential rate increase for the Company of 4.0%. This represents an increase to the typical residential bill of approximately $24

per year or $2.00 per month. These approved increases are associated with allowed expenses and return on investment only and do not contemplate increases or decreases that may occur in association with gas cost adjustments to rates as allowed by North Carolina law.

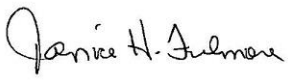
The Commission has also approved an Integrity Management Tracker mechanism, which will allow the Company to recover the capital related costs of compliance with federal pipeline and distribution integrity management requirements on an intra-rate case basis. This mechanism will facilitate timely recovery of costs related to capital investment needed to comply with federal law and will help to avoid frequent general rate proceedings.

A list of approved rates can be obtained from the Company's website, www.psncenergy.com, or at the Office of the Chief Clerk of the Commission, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, where copies of the Commission's Order and the Stipulation are available for review by any interested person. The Commission's Order, the Stipulation, and other filings in this docket, can be viewed/printed from the Commission's website at http://www.ncuc.net using the Docket Search function.

ISSUED BY ORDER OF THE COMMISSION

This the __28th__ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION



Janice H. Fulmore, Deputy Clerk

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of)		
HAWAIIAN ELECTRIC COMPANY, INC.	)	DOCKET NO. 7700
For Approval of Rate Increases and Revised Rate Schedules and Rules.	)	

DECISION AND ORDER NO. 13704

Filed December 28, 1994

At 11:03 o'clock A .M.

Chief Clerk of the Commission

ATTEST: A True Copy
CLARENCE M. NAGAO
Commission Counsel
Public Utilities Commission
State of Hawaii

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because customers pay for these items before HECO pays them to governmental authorities. The remaining components require working cash because HECO must pay for these expenses before its customers pay for the service provided by these items. The working cash requirement is calculated by multiplying the average net collection lag by the average daily operating expenditure amount.

HECO calculates its working cash requirements for the test year at $1,785,000 under present rates, and $462,000 at proposed rates. The Consumer Advocate's revised estimates are $1,609,000 at present rates, and $965,000 at proposed rates. DOD's revised estimates are $1,829,000 at present rates, and $898,000 at proposed rates.

The Consumer Advocate and DOD accept HECO's calculated revenue and expense lag days used to determine working cash requirements. The difference in the parties' estimates stems from the differences in their estimates for the various components of the working cash calculation. In attached Exhibit B, we reflect the level of expenses approved by this decision and order and the net lag days. As presented there, we adopt as reasonable, the working cash requirement of $1,879,000 at present rates and $818,000 at proposed rates.

VI.

RATE OF RETURN

A. Introduction

In deciding what constitutes a fair rate of return on HECO's rate base, we adhere, as in past rate cases, to the guidelines set forth in Bluefield Waterworks and Improvement Co. v.

Pub. Serv. Comm'n, 262 U.S. 679 (1923), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). The guidelines prescribe that a fair return must:

1. be commensurate with returns on investment in other enterprises having corresponding risks and uncertainties;

2. provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and

3. provide a return sufficient to assure confidence in the financial integrity of the enterprise to maintain its credit and capital-attracting ability.

HECO submits that a fair rate of return on its rate base for the test year is 9.67 per cent, with a rate of return on common equity of 12.75 per cent. The Consumer Advocate proposes a rate of return on rate base of 8.94 per cent, with a rate of return on common equity of 11.25 per cent. DOD recommends a 9.21 per cent rate of return, with a return on common equity of 11.8 per cent.

All parties agree that a fair rate of return should be equal to the composite cost of capital. This composite cost represents the carrying cost of money received from investors to finance the net rate base. It is the sum of the weighted earnings requirements of each element of HECO's capital structure. HECO's capital structure includes: (1) short-term debt, (2) long-term debt, (3) preferred stock, and (4) common equity.

The parties utilized the same capital structure in their rate of return analyses. They agree on the costs of short-term and long-term debt and preferred stock, but disagree on the cost of common equity. In the sections that follow, we examine and discuss each capital structure component.

B. Capital Structure

The parties agree that an average test year capital structure should be used, as prescribed by the commission in recent rate cases.[12] The Consumer Advocate and DOD agree with HECO's projected average 1994 test year capital structure, as follows:

	Amount in Thousands	Per Cent of Total
Short-term debt	$45,240	5.56 %
Long-term debt	315,065	38.69 %
Preferred stock	59,582	7.32 %
Common equity	394,492	48.44 %
Total	814,379	100.00 %

The proposed structure is consistent with HECO's declared aim to manage its capital structure so as to achieve certain average target ratios. It is also consistent with the average test year capital structure prescribed by the commission in recent rate cases.[13] The commission agrees with the parties that the proposed structure is reasonable. The debt ratio is similar to the debt ratio in HECO's last rate case and the capital structure is close to management's target.

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[12]See In re Maui Elec. Co., Ltd., Docket No. 7000, Decision and Order No. 13429 (Aug. 5, 1994); In re Hawaii Elec. Light Co., Inc., Docket No. 6999, Decision and Order No. 11893 (Oct. 2, 1992); In re Hawaiian Elec. Co., Inc., Docket No. 6998, Decision and Order No. 11699 (Jun. 30, 1992); In re Gasco, Inc., Docket No. 6434, Decision and Order No. 11464 (Apr. 32, 1992); and In re Hawaiian Elec. Co., Inc., Docket No. 6531, Decision and Order No. 11317 (Oct. 17, 1991).

[13]See In re Hawaiian Elec. Co., Inc., Docket No. 6998, Decision and Order No. 11699 (1992); In re Hawaii Elec. Light Co., Inc., Docket No. 6999, Decision and Order No. 11701 (1992); In re Gasco, Docket No. 6343, Decision and Order No. 11564 (1992).

C. Cost of Short-Term Debt

HECO's projected cost of short-term debt is 4.0 per cent. This estimate is based on HECO's cost of issuing commercial paper. HECO calculated the weighted average cost for HECO commercial paper borrowings for the first half of 1993 at 3.51 per cent. With short-term interest rates expected to increase, HECO estimates that a 4.0 per cent average cost of short-term debt for 1994 is reasonable. The Consumer Advocate and DOD agree with HECO's estimate. We agree that 4.0 per cent is a reasonable estimate of HECO's average cost of short-term debt.

D. Cost of Long-Term Debt

HECO initially estimated the average cost of long-term debt at 7.04 per cent. HECO subsequently revised its estimate to 7.07 per cent to reflect the actual rates for bonds issued in 1993. The revenue bonds issued in 1993 were sold at a discount of 2.0 per cent. The 7.07 per cent represents the embedded composite interest rate for HECO's projected long-term debt. It reflects (1) HECO's annual interest expense, (2) the annual amortization of debt premiums and issuance expenses for outstanding debt issue, (3) the annual amortization of the differential between interest earned and the sum of interest expenses and issuance costs related to undrawn proceeds from the sale of special purpose revenue bonds, and (4) the amortization of the discount on the 1993 bond issuance.

HECO used those methodologies approved by the commission in past rate cases in calculating its projected average cost of long-term debt. The parties agree with HECO's projection, and we accept the projected cost as reasonable.

E. Cost of Preferred Stock

HECO's estimate of the effective annual cost of its preferred stock is 7.3 per cent. HECO derived the effective rate of 7.3 per cent by dividing the average annual requirement of $4,349,000 by the average net proceeds of preferred stock outstanding of $59,580,000. It calculated the annual requirement by adding the annual dividends to the annual amortization of issue expense for series O, Q, and R over the lives of each issue in proportion to the amount of the issues outstanding in each year.

The Consumer Advocate and DOD agree with HECO's cost of preferred stock. We also concur and find 7.3 per cent to be a reasonable cost of preferred stock for test year 1994.

F. Cost of Common Equity

HECO submits that it should be allowed to earn a return on common equity of at least 12.75 per cent. HECO urges that the return allowed on common equity must be commensurate with returns on investments in other enterprises having corresponding risks and uncertainties, and must provide a return sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability. The Consumer Advocate proposes a return on common equity of 11.25 per cent. DOD proposes a return of 11.8 per cent.

The parties agree that the cost of common equity should be derived from market information. The parties also agree that multiple methods should be employed in determining the cost of common equity due to the judgment and limitations inherent in all methods. The parties further agree that the methods employed

should be expectational and forward-looking. However, the differences in the parties' recommended rates of return result from, among other things, (1) the use of different methodologies in determining appropriate return on equity, (2) the use of different groups of companies as comparables to HECO, (3) the use of market data from different sources, (4) the use of market data at different points in time, (5) disagreement about adjustment of the rate of return to reflect issuance cost, (6) differing assessments about HECO's business risks, and (7) differences in judgment.

1. Proxies Used

HECO's common stock is not publicly traded. Therefore, the use of the comparables technique to estimate the cost of common equity is appropriate. The comparables technique calculates the cost of common equity for a portfolio of companies whose risks are comparable to those of HECO. It assumes that the rate of return on common equity for the proxy companies is a valid estimate of the return necessary for HECO. Adjustments, based on judgment, can be made to the rate of return to account for differences between the financial, operating, and business characteristics of the comparable companies and those of HECO.

In In re Hawaiian Elec. Co., Inc., Docket No. 6531, Decision and Order No. 11317 (1991), we identified the criteria by which the appropriateness of the use of a company as a proxy is determined. We stated that a proxy company should: (1) have almost all of its revenues derived from electric operation; (2) be primarily a electric utility; (3) have tradeable common stock; (4) not be a holding company with more than one subsidiary;

(5) have a common equity ratio of 35 per cent to 50 per cent; (6) be small; (7) be substantially a regulated company; (8) have no major generating plants under construction; and (9) have stock and bond ratings similar to that of HECO.

We reaffirmed this criteria in HECO's last rate case. See Docket No. 6998, Decision and Order No. 11699. However, in Docket No. 7000, Decision and Order No. 13429, we took note of the changes in circumstances that have arisen since we established the comparables criteria in Docket No. 6531. We took particular note of the heavy construction program that HECO and its subsidiaries have embarked upon and of the rising competition in the generation of electric power. We offered that, in light of these changes, it may be appropriate for the commission's comparables criteria to be now applied advisedly.

HECO selected as its comparable electric companies those possessing the following characteristics: (1) electric business providing 90 per cent or more of company revenues; (2) regulated entity; (3) small in size; (4) regulatory environment similar to HECO's; (5) common equity ratio or financial risk similar to HECO's; (5) nuclear risk similar to HECO's; (6) minimal diversification outside of core electric business; (7) no construction of large, base load generating plant; and (8) stocks and bond rating similar to HECO's. Six companies met the standards: Atlantic Energy, Central Louisiana Electric, Delmarva Power, KU Energy, Puget Sound Power & Light, and Southwestern Public Service. All of these companies have

Value Line safety rank of 1 or 2,[14] and the average Standard & Poor's bond rating of the companies is A, two notches above HECO's BBB+.[15] In terms of regulatory environment, and common equity ratios, these companies are comparable to HECO. None of the companies is diversified in any significant way and none is building large, base load generating plants. With this group of comparables, HECO performed the discounted cash flow (DCF) analysis, market equity risk premium (MERP) test, and the capital asset pricing model (CAPM) analysis.

Contending that the risks of electric companies are no different from those of other non-electric companies, HECO also used as comparables a group of 329 companies (each with a Value Line safety rank of 1 or 2) included in the Value Line universe of 1,600 companies. HECO performed a comparable risk discounted cash flow (CRDCF) analysis on this group of Value Line companies. HECO justifies the use of these companies on the ground that (1) investors do not wear blinders and they require comparable returns for comparable risk or a fair risk-adjusted return among investments with different risks; and (2) Value Line safety rank is a measure of risk, and the safety ranks of the Value Line 329 companies it selected are comparable to the safety ranks of HECO's electric comparable companies.

The Consumer Advocate used three sets of criteria in selecting its electric comparables: general characteristics,

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[14]HEI's Value Line safety rank is 3. This ranking reflects HEI's non-utility business to some degree.

[15]HECO asserts that it had difficulty finding companies rated triple B by S&P with Value Line safety rank of 2 or better.

operating characteristics, and financial characteristics. The criteria grouped under general characteristics included (1) publicly-traded electric utility regulated primarily by one state commission; (2) geographical diversity; (3) not a holding company; and (4) no significant non-utility operations. Criteria under operating characteristics included: (1) total revenues less than $800 million; (2) electric revenues at least 80 per cent of total revenues; (3) no nuclear generation; and (4) purchased power at least 5 per cent of supply but not greater than 50 per cent. Criteria under financial characteristics included: (1) senior secured debt rated at least Baa3, but not greater than A1 by Moody's; (2) senior secured debt rated at least BBB-, but no greater than A+ by Standard & Poor's; (3) common equity ratio greater than 40 per cent, but less than 50 per cent; (4) allowance for funds used during construction less than 25 per cent of earnings; and (5) no reduction in common dividend in five years.

The selection criteria used by the Consumer Advocate in this docket differ from those it used in Docket No. 6998 (the last HECO rate case) in the following respects. The Consumer Advocate added the general characteristic category of criteria; it lowered the minimum bond rating and the maximum dollar revenue allowable; and it added a purchase power criterion. The Consumer Advocate deemed the following companies (out of the approximately 90 major electric utilities covered by Value Line and Merrill Lynch) to have met the criteria: Central Louisiana Electric, Empire District Electric, Idaho Power, Interstate Power, and Nevada Power. With this group of comparables, the Consumer Advocate applied the DCF approach and the CAPM.

DOD attempted to follow the commission's criteria in selecting its group of comparables. It asserts that it had difficulty finding a group that met all of the criteria without exception. DOD initially selected the following as comparables: Central Maine Power, Central Hudson Gas & Electric, Cincinnati Gas & Electric, DQE, Minnesota Power & Light, New York State Electric & Gas, Portland General Corporation, PSI Resources, Public Service of Colorado, and Puget Sound Power. In oral testimony, DOD eliminated Central Maine Power from the group of comparables. Due to changes in circumstances, Central Main Power no longer satisfies the standards of comparability. All remaining companies have Standard & Poor's bond rating within one step of HECO's BBB+ rating and Value Line betas of 0.65 or 0.70. (HECO's Value Line beta is 0.70.) To this group of comparables, DOD applied the DCF method, the CAPM, and a very limited version of the comparable earnings test to determine the rate of return on common equity.

DOD also used HEI, HECO's parent company, as a proxy for HECO, and applied the DCF, risk premium (RP), CAPM, and the comparable earnings tests to HEI. In addition, DOD used Moody's 24 electric companies as comparables and applied the RP test to this group.

2. The Methodologies Applied

As noted above, HECO applied the DCF, the MERP, and the CAPM tests to its group of electric comparables and the CRDCF model to a group of Value Line companies to determine the cost of common equity for HECO. The Consumer Advocate applied the DCF method and the CAPM to its group of comparables. DOD applied the DCF, the

CAPM, and a limited version of the comparable earnings test to its group of comparables and to HEI. DOD also used the RP model on HEI and Moody's 24 electrics. In addition, as a check, it applied the DCF, CAPM, and the limited version of the comparable earnings approaches to HECO's group of electric comparables.

The DCF method is a stock valuation approach to estimating the cost of common equity. The most commonly applied version of the DCF method is the constant growth DCF. In this method, the required rate of return is the sum of (1) the current dividend yield, represented by the ratio of expected next-period dividends to current stock price, and (2) the expected constant dividend growth rate. The underlying theory of the constant growth DCF method is that the market price an investor pays for a share of stock represents the present value of expected future dividend yields, grown at a constant rate. The future flow of dividend yields is discounted at a rate reflecting investor preference for current income and investor assessment of dividend realization risk. Thus, the rate of return on common equity capital under the DCF model is the rate that compensates investors for risk and time, assuming that the security is efficiently priced. Estimation of the DCF rate of return requires estimates of the current dividend yield and the dividend growth rate.

The CRDCF method is procedurally identical to the DCF method. In this docket, the CRDCF method is the DCF method applied by HECO to the Value Line companies. As already noted, the underlying assumptions in the use of the CRDCF method are that the risks in electric utilities are comparable to the risks in other non-electric utility companies and that investors consider a

variety of stocks when investing and they require comparable returns for comparable risks or a fair risk-adjusted return among investments with different risks.

Under the RP method, the rate of return is the sum of (1) the rate of return on risk-free, long-term debt and (2) a risk premium for the additional risk associated with the stock in question. The proxy for the risk-free rate is generally the rate on long-term United States government bonds. The risk premium is the difference between the rate on long-term United States government bonds and the expected return on the common stock. The RP method uses the DCF analysis of investor expected returns to calculate the equity risk premium

The MERP test is similar to the RP test. The difference is that, while the RP method uses CDF-derived expected returns of the stock in question and expected bond returns, the MERP test uses the actual market returns of both stock and bonds to determine the equity risk premium.

The CAPM is a variation of the risk premium approach. As in the RP method, the required rate of return under the CAPM is the sum of (1) a risk-free component, which constitutes the floor on expected return and is generally measured by the return on long-term United States government bonds, and (2) a risk premium component, which represents an additional return over the riskless rate required to compensate investors for bearing additional risk. However, the risk premium under the CAPM is proportional to the "nondiversifiable" (or "systematic") risk of the security in question (the security-specific risk that cannot be eliminated through diversification).

The nondiversifiable risk is obtained by applying the appropriate beta to the amount by which the average market return exceeds the risk-free rate of return. Beta is a measure of the relative risk of a security compared to the risk of the average market stock. The beta for the market is set equal to one. A stock with a beta greater than one is more risky than the average market stock, and a stock with a beta less than one is less risky than the average market stock. The use of CAPM to determine the rate of return on common equity requires estimates of the risk-free rate, the stock's beta, and the rate of return on the market.

3. The Parties' Analyses

a. HECO

HECO's estimate of the rate of return on common equity is based on calculations made by its expert witness, Charles A. Benore, first vice-president, PaineWebber, Inc. Mr. Benore first applied the market equity RP test to his group of comparables. Initially he estimated the cost of common equity on the RP method at 12.0 per cent, without issuance costs. With issuance costs of 30 basis points, Mr. Benore's initial cost of common equity was 12.3 per cent. In his calculation, Mr. Benore used the average daily closing yields of long-term United States government bonds of 6.92 per cent for the month beginning April 28, 1993, to May 27, 1993. For the risk premium, Mr. Benore first determined the average equity risk premium for the last economic cycle, 1983 to 1991, for each of his comparable companies. He then averaged the values of the three companies with the highest values to derive an average risk premium of 5.1 per cent. He average only

the three highest values to compensate for HECO's higher risk as compared to the comparable companies. He derived his cost of common stock equity by combining the risk free rate of 6.92 per cent and the risk premium of 5.1 per cent. In rebuttal, Mr. Benore increased the cost of common equity initially derived by 0.5 per cent to account for the higher returns on electric stocks now required by investors as a result of increased competition in the electric industry.[16] However, there is some confusion in Mr. Benore's calculation. Mr. Benore's revised cost of common equity on the market equity RP method is 12.2 per cent, including issuance costs, 0.1 per cent less than his initial calculation of 12.3 per cent.

Mr. Benore's application of the CAPM model to his group of comparable companies resulted initially in cost of common equity of 12.7 per cent, before issuance costs, and 13.0 per cent with issuance costs. In arriving at this result, Mr. Benore used as the risk free rate the average yield to maturity on long-term United States government bonds of 6.92 per cent for the month of May 1993. For beta, Mr. Benore used an adjusted beta of 0.92. The adjusted beta is the weighted average based on the proportion of the stocks of the comparable companies held by institutional and individual investors, using the Value Line beta for the institutional investors and a beta of 1.0 for individual investors. Mr. Benore justifies the use of an adjusted beta by noting that

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[16]Mr. Benore notes a shift in investors' requirement of electric stocks from about 90 basis points less to about 40 basis points more than yields on treasury bonds during the period July 1993 to October and November 1993. Mr. Benore used DOD's group of electric comparables for this analysis.

(1) for beta to work, adequate diversification is crucial, (2) the minimum number of stocks needed to be held by an investor for proper diversification is fifteen, (3) individual investors typically own only about three stocks, and (4) 78 per cent of the shares of the comparable companies are owned by individuals. For the average expected market return, Mr. Benore used 13.1 per cent. The 13.1 per cent is the sum of the blended growth rate of 10.2 per cent for Standard & Poor's 500[17] and the yield on a 12-month forward dividend of 2.9 per cent.

On rebuttal, Mr. Benore revised the results obtained through the application of the CAPM to account for the higher returns now required by investors on electric stocks because of increased competition in the electric industry. Mr. Benore deemed that an upward adjustment should be made to his initial calculation. Taking into account the inability of individual investors to diversify away competition risk, Mr. Benore increased the cost of common stock indicated by the CAPM by two-thirds of the 0.5 per cent cost of common not captured by the equity risk premium model, or 0.3 per cent. (Mr. Benore's use of two-thirds is derived from the premise that, on the average, two-thirds of the shares of electric power companies are owned by individuals.) Again, as in the risk premium revised calculation, there is some confusion in the resulting recommended cost of common equity under the CAPM. Mr. Benore's revised CAPM cost of common equity is 13.1 per cent,

[17]The blended growth rate, as calculated by Mr. Benore, is the dividend growth for the last five years and the projected earnings growth for the next five years, with more weight given to projected growth rate.

including issuance costs, just 0.1 per cent more than his initial calculation.

Mr. Benore's initial calculation of the cost of common equity under the DCF model, as applied to his group of electric comparables, was 10.1 per cent, including issuance costs of 30 basis points. On rebuttal, Mr. Benore revised his calculation to 10.2 per cent, including issuance costs. In computing dividend yield, Mr. Benore increased the current dividend by the applicable growth rate at the normal, dividend change, timing pattern for the comparable companies. Where dividend had not been increased on a regular basis and four quarters or more of time had passed without a dividend increase, Mr. Benore increased dividend in the second quarter of 1993. For stock price, Mr. Benore used the average price for a 20-day trading period, beginning April 28, 1993, to May 27, 1993. To the yield derived (dividing forward dividend by price), Mr. Benore added the growth rate derived from Value Line and International Brokers Estimate System (IBES). The growth rate is a blending of the historical and projected growth rates.[18] Mr. Benore then applied the DCF equation and derived a cost of common equity for each of the comparable electric companies. He eliminated the lowest three results, to reflect HECO's higher risks, and averaged the three highest results to obtain a DCF cost of common equity of 9.8 per cent, before issuance costs, and

[18]Mr. Benore derived the blended growth rate by first averaging Value Line projected dividend per share (DPS) growth rate and Value Line projected earnings per share (EPS) growth rate. He then averaged the average Value Line projected growth rate and the IBES projected growth rate. Finally, Mr. Benore averaged the average Value Line and IBES growth rate and Value Line historical five-year DPS growth.

10.1 per cent with issuance costs. On rebuttal he revised his calculation to 10.2 per cent, with issuance costs.

Mr. Benore's application of the DCF method to the group of 329 Value Line companies resulted initially in a cost of common equity of 13.0 per cent, with issuance costs. For his calculation, Mr. Benore used the average yield of 3.66 per cent for the 329 companies, based on a June 1, 1993, Value Line report,[19] and an average last five-year growth rate of 9.0 per cent.[20] As a check on his calculation, Mr. Benore calculated the DCF cost of common stock of 25 companies having Value Line safety rank of 1 or 2 and Value Line beta of 0.90. This calculation produced a 13.2 per cent cost of common equity. Noting that his group of electric comparable companies also have Value Line safety ranks of 1 or 2 and an adjusted beta of 0.92, Mr. Benore would have us accept the result of his DCF calculation, using Value Line companies, as a reasonable index of HECO's cost of common equity. On rebuttal, Mr. Benore revised the cost to 13.2 per cent, with issuance costs.

The average of Mr. Benore's calculations of the costs of common equity, utilizing the MERP method, the CPM, the DCF model applied to his electric comparable, and the DCF model applied to the Value Line companies, is 12.2 per cent (based on the revised

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[19]In calculating the DCF cost of common equity, based on his electric comparables, Mr. Benore used an average period price, rather than a spot price. In the case of the Value Line 329 companies, Mr. Benore used a spot price on the ground that the number of companies involved made the average yield likely to be unbiased.

[20]Per Value Line, the dividend growth rate of the 329 Value Line companies for the past five years averaged 9.6 per cent, and the projected earnings and dividends growth rate averaged 8.4 per cent. The average of the averages equals 9.0 per cent.

figures). Mr. Benore argues that because of the downward bias inherent in the DCF test, as applied to his electric comparables, the results of the electric comparable-DCF test should be disregarded. Mr. Benore offers that the current inflated prices of electric common stocks and the consequent excessive price-to-book ratio produce absurd DCF results. Without the electric utility DCF result, the average cost of common equity of all tests is 12.8 per cent. Mr. Benore recommends a cost of common equity for HECO of 12.75 per cent.

b. The Consumer Advocate

The Consumer Advocate's proposed cost of common equity is based on calculations made by its expert witness, J. Robert Malko, professor of finance, College of Business, Utah State University. Dr. Malko made two DCF calculations, one based on historical growth and the other on projected growth. For historical growth, Dr. Malko averaged Value Line's past five-year and 10-year historical growth rates for each of his comparable companies.[21] The average ranged from 1.8 per cent to 5.5 per cent for his group of comparable companies. For projected growth rate, Dr. Malko consulted (1) Value Line forecasts of growth in earnings, dividends, and book value and (2) IBES estimates of earnings growth.[22] Dr. Malko settled on a range of projected growth rate of

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[21]Based on Value Line Investment Survey, 1993 edition.

[22]The Value Line forecasts are from Value Line Investment Survey, 1993 edition. The IBES forecasts are those contained in the November 18, 1993, issue. Dr. Malko represents he focused primarily on mean earnings growth estimate from IBES, using the high and low values to assess the disparity in estimates, and he used Value Line forecasts as the lower bound. Dr. Malko further

1.5 per cent to 3.5 per cent. For dividend, Dr. Malko used Value Line's forecast, and for price, Dr. Malko used the current market price taken from the March 1, 1994, issue of the Wall Street Journal. The calculation, using an average historical growth rate, produced a range of returns on common equity for Dr. Malko's group of comparable companies of 9.1 per cent to 11.9 per cent, with a mean of 10.5 per cent. The use of the projected growth rates produced a range of 9.3 per cent to 10.1 per cent, with a mean of 9.8 per cent. Averaging the results of the historical growth calculation and the projected growth calculation produced a range of 9.2 per cent to 11.0 per cent.

Dr. Malko also made two CAPM calculations, one based on historical returns and the other on projected expected returns. Dr. Malko would use the CAPM (or any other risk premium model) to calculate the cost of common equity only in conjunction with the DCF method. CAPM does not incorporate dividend yield into the pricing of securities (whereas DCF does). Dr. Malko believes that beta is not the only risk factor priced by the market, that dividends are also an important factor that explains stock price. Dr. Malko contends that CAPM will underestimate the cost of equity for electric utilities because they tend to have low betas. Low beta stocks have higher returns than the CAPM predicts, and high beta stocks have lower returns than CAPM predicts.

For his CAPM calculation, Dr. Malko used a five-year United States treasury note for the risk free rate. He used a

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represents that his dividend growth forecasts are all slightly below the IBES mean earnings growth estimate. He considers his estimate to be a conservative estimate, allowing for any overestimation of earnings growth.

five-year treasury note because it represents a mid-point between a 30-day treasury note and a 30-year treasury note. He notes that a 30-year treasury note contains a maturity premium to compensate investors for interest rate risk[23] and a 30-day note has volatility. Neither is, thus, risk free. Further, Dr. Malko believes that a five-year treasury note is consistent with equity investors' planning horizon and results in little or no maturity premium considering current interest rates. Dr. Malko used a risk free rate of 5.9 per cent, as noted in the March 1, 1994, issue of the Wall Street Journal.

For beta, Dr. Malko used the average betas published in Merrill Lynch Security Risk Evaluation, November 1993, and in Value Line Investment Survey, 1993 edition.[24] The Merrill Lynch betas ranged from 0.57 to 0.73, with an average of 0.62. The Value Line betas ranged from 0.45 to 0.65, with an average of 0.55. Dr. Malko averaged the Merrill Lynch average and the Value Line average to derive a beta of 0.59.

For historical expected excess returns for each of his comparable companies, Dr. Malko extracted data from Ibbotson Associates' Stocks, Bonds, Bills, and Inflation 1993 Year Book. Both the intermediate-term United States government bonds

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[23]A risk that interest rate may rise or fall during the 30-year period. A 30-year treasury bond is issued at a rate that is fixed over the 30-year period.

[24]Merrill Lynch betas are raw betas, based on the S&P 500 composite index, using straight regression based on five years of monthly returns or 60 observations. Value Line betas are derived from regression analysis between weekly per cent changes in the price of stock and weekly per cent changes in the New York Stock exchange composite indices over a five-year period. Value Line reports betas are adjusted for tendency to converge toward 1.0.

(five-year bonds) and common stock total returns were measured from 1926 to 1992. The common stock total return index was based on the S&P composite index. The arithmetic mean of the intermediate-horizon risk premiums equaled 7.30 per cent. For the projected expected excess returns, Dr. Malko used Value Line data. Using February 25, 1994, Value Line data, Dr. Malko calculated a projected excess return of 7.30 (the same excess return or risk premium as calculated using historical data).

Since the historical and projected excess returns were the same, the CAPM calculation using historical expected excess return and the CAPM calculation using projected expected excess return produced the same result. Adding the risk free rate (5.9 per cent) and the product of beta times the excess return on the market resulted in a CAPM cost of common equity for the comparable companies between 9.7 per cent to 10.8 per cent, with an average of 10.2 per cent.

Dr. Malko's recommended cost of common equity for HECO is 11.25. This cost represents the high end of the results of his DCF and CAPM calculations. He acknowledges that the 11.25 per cent is higher than the averages of his DCF estimates (10.0 per cent) and his CAPM estimates (10.2 per cent). However, he recommends the higher end because HECO's business risks are higher than those for his portfolio of comparable companies as evidenced by, among other things, HECO's split bond ratings, significant construction program, and purchased power obligations.

c. DOD

DOD's proposal on the cost of common equity is based on calculations made by its expert witness, John B. Legler, professor of banking and finance at the University of Georgia. Dr. Legler first calculated the cost of common equity utilizing the DCF method. He calculated the DCF results for HEI and his group of comparable electric companies. For HEI, Dr. Legler used a growth rate ranging from 4.5 per cent to 5.5 per cent. The growth rate was derived from historical earnings and dividend growth rates, retention growth rate,[25] and Value Line forecasts. For price, Dr. Legler initially used $38.02, the average HEI's stock price for the three-month period August 1993 to October 1993. For dividend, Dr. Legler used the expected dividend for 1994 of $2.33.[26] The resulting calculation produced a DCF cost of common equity for HEI of 10.6 per cent to 11.6 per cent. At the price prevailing on October 29, 1993 ($37.785), the DCF results ranged from 10.7 per cent to 11.7 per cent. Dr. Legler subsequently revised his estimates, using the December 1993 to February 1994 prices. Based on the December to February average, Dr. Legler calculated HEI's DCF cost of common equity at 11.23 per cent to 12.3 per cent.

For his group of electric comparables, Dr. Legler initially calculated a DCF cost of common stock of 8.20 per cent to 9.23 per cent, based on average stock prices between August 1993 to

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[25]Retention growth rate is the product of percentage of earnings retained times earned rate of return on equity.

[26]The $2.33 was derived by adding to current dividend of $2.32, $0.01 increase in dividend for the next year. HEI had increased its dividend by $0.01 a share in the fourth quarter of each of the last several years.

October 1993, and 8.37 per cent to 9.45 per cent, based on October 29, 1993 stock prices. On oral testimony, Dr. Legler revised his results to reflect the elimination of Central Maine Power from his group of electric comparables and to reflect the average stock prices between December 1993 and February 1994, and the stock price prevailing on February 28, 1994. As revised, the DCF cost of common equity for Dr. Legler's group of electric companies range from 8.63 per cent to 9.66 per cent, based on the average December to February prices, and from 8.88 per cent to 9.96 per cent, based on February 28, 1993, stock prices.

Dr. Legler does not believe that primary reliance should be had on the traditional risk premium (RP) method of estimating cost of common equity, due to volatile conditions and interest rate risk in the long-term bond market. Despite his reservations, Dr. Legler performed risk premium analyses on HEI and Moody's 24 electrics. Risk premiums are based on the differentials between the expectant returns on stocks and on long-term debt. The stock returns are based upon the DCF method.

For HEI, Dr. Legler calculated the risk premium on both retention (or sustainable) growth and analyst's forecasted growth. The retention growth rate is based on Value Line's projected data for earnings per share, dividends per share, and return on equity from its published reports on HEI towards the end of each year, 1978 to 1993; and the analysts' forecasted growth rate is based on Value Line's direct forecasted dividend growth rates. Dr. Legler derived the risk premium for HEI by first estimating HEI's cost of equity for the first of January of each year beginning 1979, based on the data in Value Line's report published toward the end of the

previous year, and then comparing each year's estimate to the 30-year treasury bond rate for December of the previous year. He also compared the expected return on HEI stock to the existing bond yield at the time Dr. Legler assumed to be the reported December Moody's public utility bond yield for the single-A rating class of the previous year. The difference between the DCF calculated return on equity and the then-current bond yield constituted the risk premium. Dr. Legler, then, averaged the risk premiums of the years in question.[27] Dr. Legler's calculations resulted in an average risk premium, based on the DCF analysis using Value Line's retention growth, of 2.75 per cent, relative to the treasury bond yield for the period 1979 to 1994. Relative to the treasury bond yield for the last five-year period, 1990 to 1994, the premium averaged 2.19 per cent. Relative to appropriate utility bond rates, the risk premium averaged 4.48 per cent for the period 1979 to 1994, and 1.17 per cent for the shorter period. The risk premium, based on the DCF estimated returns using Value Line's direct dividend growth forecasts, averaged 4.46 per cent relative to treasury bond and 2.87 per cent relative to utility bonds for the longer period, and 2.43 per cent and 1.05 per cent, respectively for the shorter term.

For the long-term debt component of the risk premium model, Dr. Legler initially used the November 4, 1993, 30-year United States government bond rate of 6.17 per cent. He also used the November 4, 1993, single-A rated public utility bond rate of 7.27 per cent. Dr. Legler in his written testimony calculated the

[27]In averaging the risk premium results for the years 1979 to 1994, Dr. Legler excluded all negative risk premiums.

cost of common equity for HEI, based on long-term risk premium and treasury bond yield, at 8.92 per cent, at the retention growth rate, and 10.63 per cent, at Value Line's forecasted dividend growth rate. Based on short-term risk premium and treasury bond yield, Dr. Legler calculated the cost of common equity for HEI at 8.36 per cent at the retention growth rate and 8.51 per cent at the Value Line's forecasted dividend growth rate. Dr. Legler calculated the cost of common equity for HEI, based on long-term risk premium and utility bond yield, at 8.75 per cent, at the retention growth rate, and 10.14 per cent at the Value Line's forecasted dividend growth rate; based on short-term risk premiums and utility bond yield, Dr. Legler calculated the cost of common equity for HEI at 8.31 per cent at the retention growth rate and 8.44 per cent at the Value Line's forecasted dividend growth rate.

Dr. Legler applied the risk premium analysis to Moody's 24 electrics in a manner similar to the application of the method to HEI, except for the calculation of the growth rates. For Moody's 24 electrics, Dr. Legler based the growth rate, first, on a five-year moving average historical retention growth rate and, second, on a five-year historical dividend growth rate. The application of the risk premium method to Moody's 24 electrics produced a risk premium, relative to treasury bond, averaging 10.03 per cent, based on the historical retention growth rate, and 4.41 per cent, based on the historical dividend growth rate. Relative to utility bond yield, the calculation produced a risk premium averaging 9.49 per cent, based on the historical retention growth rate, and 10.04 per cent, based on the historical dividend growth rate.

Dr. Legler posited that overall, the cost of common equity, based on the risk premium model, should be about 10.6 per cent. On oral testimony, however, Dr. Legler acknowledged the rise in 30-year treasury bond rates of roughly 60 basis points since he prepared his written testimony. Therefore, he revised his estimate of the risk premium cost of equity to 11.2 per cent.

Dr. Legler is skeptical about using CAPM in estimating the cost of common equity. He asserts that ordinarily he does not use CAPM. However, he prepared calculations of the cost of common equity using the CAPM because this commission has in the past utilized the results of CAPM analysis in determining the cost of common equity. Dr. Legler used both the S&P betas and the Value Line betas in his calculation of the cost of common equity. Dr. Legler notes that Value Line reports that its betas are adjusted for their long-term tendency to converge towards 1.0.[28] Dr. Legler questions the truth of that statement, but applied Value Line's betas, nonetheless. S&P betas are unadjusted, raw betas. Value Line betas and S&P betas for Legler's group of electric comparables averaged 0.67 and 0.51, respectively. HEI's Value Line beta is 0.70, and its S&P beta is 0.59.

Based on the long-term historical market premium of 7.3 per cent and a risk-free 30-year United States Treasury bond rate of about 6.2 per cent, Dr. Legler calculated, in his written testimony, a cost of common equity for his group of comparables of 11.09 per cent, based on Value Line average beta, and 9.92 per cent, based on S&P average beta. For HEI, Dr. Legler derived a

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[28]Arnold Bernhard, How to Use the Value Line Investment Survey, at 61.

cost of common equity of 11.31 per cent, based on Value Line beta, and 10.51 per cent, based on S&P beta. For comparison, Dr. Legler calculated the cost of common equity for Mr. Benore's group of comparables, using the average Value Line average beta of 0.62 and average S&P beta of 0.44 per cent for that group of comparables. The results were 10.73 per cent, based on Value Line average beta, and 9.41 per cent, based on S&P average beta. In light of the rise in United States Treasury bond rates, in oral testimony Dr. Legler raised the CAPM cost of common equity for his comparable electrics, based on Value Line average beta, from 11.09 per cent to 11.7 per cent.

Dr. Legler performed a limited comparable earnings analysis. Dr. Legler did not perform the standard, traditional comparable earnings test in this docket, primarily because of the difficulty in determining what companies are comparable to the utility in question. Dr. Legler rejected the use of industrials as the only basis of comparison because of questionable comparability of the measured earnings and differences in risks of regulated and unregulated companies. Dr. Legler posits that his DCF analysis parallels the traditional comparable earnings approach and leads to the same conclusion.

However, Dr. Legler reviewed Value Line's direct estimates of the returns on book equity for the groups of comparable electrics and HEI. Value Line average projected returns for 1993, 1994, and 1996-1998 are 11.4 per cent, 11.3 per cent, and 11.7 per cent, respectively, for Legler's group of comparables. They are 9.5 per cent, 10.0 per cent, and 11.0 per cent, respectively, for HEI; and 12.0 per cent, 11.9 per cent, and

12.6 per cent, respectively for Mr. Benore's group of electric comparables. Dr. Legler concludes that these estimates suggest the reasonableness of his own estimates for his group of comparable electrics.

Based on the commission's precedent of considering the results of all three methodologies--DCF, RP, and CAPM--of averaging the average of the RP and CAPM results and the DCF result, Dr. Legler in his written testimony recommended a cost of common equity for HECO ranging between 10.8 per cent and 11.3 per cent, without issuance costs, and 11.0 per cent and 11.5 per cent with issuance costs of 20 basis points. In developing this range, Dr. Legler utilized (1) the mid-point of the HEI DCF results using average prices (11.3 per cent), (2) the upper end of HEI risk premium results based on longer-term risk premiums (10.6 per cent), and (3) the CAPM range of 9.9 per cent to 11.1 per cent. He also considered the trend in the stock market, the recent interest rates, and HECO's relative riskiness. For purposes of calculating a weighted average cost of capital, Dr. Legler recommended a cost of common equity of 11.25 per cent, the mid-point of the range. On oral testimony, Dr. Legler noted that his revisions place his DCF estimate at about 11.8 per cent, the RP estimate at about 11.2 per cent, and the CAPM estimate at 11.7 per cent, for a weighted average of 11.6 per cent. With 20 basis points added for issuance costs, the revised recommended cost of common equity is 11.8 per cent.

4. Discussion

a. HECO's comparables and methodologies

Primary issues in determining HECO's appropriate rate of return on common equity in this docket are HECO's use of the comparable risk DCF method and its use of "adjusted" beta in its CAPM analysis. In addition to the group of companies selected in accordance with the commission's criteria, HECO used as comparable companies 325 out of the universe of 1600 Value Line companies and applied the DCF method to that group of companies. As applied to this group of companies, the DCF method is re-named the comparable risk DCF. The comparable risk DCF method applied to the 329 Value Line companies having a safety ranking of 1 or 2 produced a cost of common equity of 13.2 per cent, a result far greater than the results produced by HECO's use of other methodologies.

Mr. Benore defends the use of the Value Line companies on the basis of that investors do not invest only in electric stocks and that investors require comparable returns for comparable risks. The sole basis for equating the risks of HECO to the risks of 329 Value Line companies is the similar Value Line safety ratings for the 329 Value Line companies and the six electric companies selected by HECO as electric comparables. In Decision and Order No. 11699, Docket No. 6998 (HECO's last rate case) and in Decision and Order No. 11893, Docket No. 6999 (HELCO's last rate case), we rejected the results of the application of the CRDCF model to the S&P 500 on the ground that the use of the S&P composite index of 500 common stocks is a departure from the use of "comparables" as we defined that term in Docket No. 6531. We noted in those decisions that S&P 500 companies are significantly more risky than

electric companies, since S&P companies operate in an environment where competition is more pronounced than in the environment in which electric utilities exist. Then, in Decision and Order No. 13429, Docket No. 7000 (MECO's last rate case) we rejected the use of Value Line companies for the same reason we rejected the use of the S&P 500 common stocks. We indicated there that the use of Value Line safety rankings as the sole criterion for determining comparability of the Value Line companies with HECO is insufficient and that comparables should be chosen on the basis of several indices to ensure that they are close to the utility in question in terms of risk, financial strength, and other characteristics. We noted in footnote 34 of Decision and Order No. 13429 some other possible criteria that could be applied.

As noted earlier, in Decision and Order No. 13429, we did acknowledge that it may now be appropriate, in light of changing circumstances, for the criteria for the selection of comparable companies, established by the commission in October 1991 in Docket No. 6531, to be applied advisedly. However, as stated in Decision and Order No. 13429, the commission will not accept Value Line companies as proxies for HECO, based solely on the asserted comparable risks determined through the application of Value Line safety ratings.

HECO's adjustment of betas in the computation of the cost of common equity using the CAPM was addressed in Decision and Order No. 13429, Docket No. 7000. We know of no one, other than Mr. Benore, in behalf of HECO, proposing weighting beta by the proportion of the stock held by institutions and by individuals. We know of no jurisdiction that has accepted such adjustment, and

we know of no text on finances that validates adjustments of beta to account for holdings by individual investors of stocks in a minimal number of companies. We note Dr. Legler's observations that Mr. Benore's adjustment of betas allows institutional investors to receive a return greater than they require and rewards individual investors for their failure to diversify away risk at the expense of ratepayers, and that under Mr. Benore's beta adjustment approach, two utilities with the same beta may have different required returns, depending on the percentage of one or the other types of investors in each.

A comment is also in order concerning HECO's use of the market equity risk premium model. In the application of this model, HECO applied the actual returns (as contrasted to expected returns) on bonds and stocks derived during the last economic cycle, 1983 to 1991, to determine equity risk premium. In Decision and Order No. 13429, Docket No. 7000 (MECO's last rate case), we expressed our preference for the use of expected returns, since investors invest based on return expectations. We acknowledged that the difference between expected returns and realized returns should diminish over a long period, as lower returns experienced over short-run periods are offset by higher returns over other short-run periods. However, we questioned Mr. Benore's use of the actual returns during the economic cycle 1983 to 1991. (Mr. Benore testified for MECO in that docket.) We questioned the sufficiency of the length of that period for the difference between expected returns and realized returns to narrow. In this docket, Mr. Benore represents that the equity risk premium has been relatively stable from one economic cycle to another, citing the average equity risk

premium of 6.5 per cent for the 1976 to 1982 economic cycle, as compared to the average equity risk premium of 6.3 per cent over the 1983 to 1991 economic cycle. We are not satisfied that the economic cycle of 1983 to 1991 provides a sufficient length of time for the actual returns over that period to be used in determining equity risk premium. However, as we did in Decision and Order No. 13429 for MECO, we will use Mr. Benore's results of the equity risk premium test, based on actual returns, as an indicator of the cost of HECO's common equity.

b. DOD's comparables

HECO objects to the use of HEI by DOD in calculating the cost of HECO's common equity. However, DOD notes that a parent company is sometimes used as a proxy for the utility in question. We are aware that HEI is not the same as HECO. HEI is a holding company with a number of subsidiaries, a number of which are not regulated electric utilities. For purposes of this docket, however, we will consider the results produced by DOD's application of the various costing methods in determining HECO's cost of common equity. The use of HEI tended to produce results on the higher end of the range of results produced by the various methodologies.

While we accept the results of the application of the various costing methodologies to HEI, we do not accept the results of the RP method applied to Moody's 24 electrics. There is nothing in the record to show on what basis Moody's 24 electrics may be deemed to be comparable to HECO. In Decision and Order No. 13429, we rejected the use of S&P 24 electrics by MECO solely on the basis of bond ratings falling within one rating of MECO's bonds. As

stated there, comparables should be chosen on the basis of a number of indices.

c. Commission's calculation of the cost of common equity

As in other dockets, experts disagree on the relative merits of the various methods of determining the cost of common equity. In this docket, both Dr. Malko and Dr. Legler would use the risk premium method and the CAPM with caution. On the other hand, Mr. Benore would give little, if any, weight to results produced by the traditional constant growth DCF. The position asserted by Mr. Benore in this docket is the same as that he advanced in Dockets No. 6998, No. 6999, and No. 7000. We are cognizant of the limitations of the DCF method. There are, however, shortcomings to be found in other methods, as well. Again, as before, we will consider the DCF, the RP, and the CAPM results in determining a utility's cost of common equity. The results of the DCF method and the combined results of the RP method and CAPM should be given equal weight.

The determination of a reasonable cost of common equity is ultimately a matter of informed judgment. We begin our analysis with the range of rates of return on common equity offered by each of the parties' witnesses. HECO presented four estimates, using four different methodologies: MERP, CAPM, electric utility DCF, and Value Line comparable risk DCF. We discard the result of the comparable risk DCF for the reasons stated above concerning utilization of Value Line companies as comparables to HECO. Although we have reservations about the use of a short period by

HECO in calculating equity risk premium in its MERP analysis, we will use HECO's MERP result with caution, since it is close to DOD's RP and CAPM results. We also discard the result of HECO's CAPM analysis because of the beta adjustments made by Mr. Benore. We will use all of the results of the DCF and CAPM analyses conducted by the Consumer Advocate. We also accept the results of all of the calculations made by DOD, except the results of the application of the RP method to Moody's 24 electrics, for the reason stated earlier. We acknowledge the concerns of HECO about the ability of HECO to earn the allowed return under the Consumer Advocate's and DOD's calculated results. However, any deficiency in the Consumer Advocate's or DOD's analyses can be accounted for in our final determination of HECO's cost of common equity.

The following summarizes the parties' calculations of the cost of common equity.

Party	Methodology	ROE With Issuance Cost	ROE Without Issuance Cost
HECO	DCF	10.2%	9.9%
HECO	MERP	12.2%	11.9%
CA	DCF		10.0%
CA	CAPM		10.2%
DOD	DCF	12.0%	11.8%
DOD	RP	11.4%	11.2%
DOD	CAPM	11.9%	11.7%

In our calculations below, we ignore issuance costs. We consider issuance costs later in our discussion. If we average HECO's, the Consumer Advocate's, and DOD's DCF results we derive an average DCF cost of common equity of 10.6 per cent. The Consumer Advocate's and DOD's CAPM results average 11.0 per cent. The

average of HECO's MERP and DOD's RP and CAPM results is 11.4 per cent. If we follow our past practice of averaging the results produced by the DCF approach and the risk premium method (including the MERP and CAPM results), we calculate a cost of common equity of 11.0 per cent.

We now consider the arguments raised by HECO. HECO asserts that the results obtained from the application of the DCF model should be given little, if any, weight, due to the downward bias inherent in the results, that adjustments must be made for MECO's higher risks as compared to those of the comparable companies selected pursuant to the commission's criteria, and that issuance cost should be included in any computation. We agree with HECO that there is currently a downward bias in the DCF model. However, we do not consider such downward bias as justifying the total elimination of the results derived from the application of the DCF model. We consider the use of the results of the DCF model, with caution, and make such adjustments as we deem appropriate in our final cost of common equity.

We also agree that HECO's business risk is higher than the business risks of the comparables used by all of the parties. The reliance on imported oil as fuel source, the lack of interconnection with reliable outside sources of power, and the need for capital investments are factors that make investment in HECO more risky than investments in other companies. In addition, the current national and local economic conditions and HECO's minimal investment grade bond rating are matters of concern. Taking all of these risk factors into consideration, we believe that an upward adjustment of 115 basis points to the 11.0 per cent

cost of common equity derived above is appropriate. Such an adjustment is necessary to allow for HECO's business and financial risks. It also recognizes the effects of national and local economies and the currently increasing interest rates. By this adjustment the rate of return on common equity rises to 12.15 per cent.

The 12.15 per cent is higher than HECO's, the Consumer Advocate's, or DOD's calculated return on common equity, without issuance costs. It is close to HECO's MERP result and to DOD's DCF and CAPM results, with issuance costs. We, thus, consider it unnecessary to consider in this docket the relative merits of allowing for stock issuance costs, although HECO strenuously argues for issuance costs of 30 basis points and DOD recommends issuance costs of 20 basis points. Upon consideration of all factors, we conclude that a rate of return of 12.15 per cent on common equity is reasonable.

G. Cost of Capital

As a result of our conclusions regarding the average-year capital structure and the cost of the various component parts of HECO's capital structure, the overall weighted cost of capital for HECO for test year 1994 is 9.38 per cent.

	Capitalization Amount (000s)	Per Cent	Cost Rate	Weighted Capital Cost
Short-term debt	45,240	5.56	4.00%	0.22%
Long-term debt	315,065	38.69	7.07%	2.74%
Preferred stock	49,582	7.32	7.30%	0.53%
Common equity	394,000	48.44	12.15%	5.89%
Total	$814,379	100.00		9.38%

Upon weighing all the evidence in this proceeding, a fair and reasonable return to HECO in its properties actually used and useful for public utility purposes is 9.38 per cent for test year 1994. This return, in the commission's opinion, satisfies the guidelines set forth in Bluefield and Hope.

VII.

COST OF SERVICE, REVENUE ALLOCATION, AND RATE DESIGN

A. Cost of Service

In its embedded cost of service study, HECO followed these three major steps in allocating the utility's total cost to the various rate classes: (1) functionalization of costs and rate base items into the major operating functions of production, transmission, and distribution; (2) classification of these functions into energy-related, demand-related, and customer-related cost components; and (3) allocation of these cost components to the various rate classes.

In the functionalization step, HECO assigned all costs associated with generation, including fuel cost and purchased power expense, to the production function. It assigned all costs associated with transferring power from power plants to substations or between switching stations at transmission voltage levels to the transmission function. It assigned all costs associated with delivering power from transmission voltage levels through the distribution system to the customer to the distribution function.

In the classification step, HECO followed the cost classification rationale contained in NARUC's Electric Utility Cost Allocation Manual. Following that rationale, HECO assigned the

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 15-155 September 30, 2016

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on November 6, 2015, to be effective December 1, 2015.

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I. INTRODUCTION

On November 6, 2015, Massachusetts Electric Company ("MECo") and Nantucket Electric Company ("Nantucket Electric"), together doing business as National Grid ("National Grid" or "Company") filed a petition with the Department of Public Utilities ("Department") for an increase in its base distribution rates for electric customers. National Grid was last granted an increase in electric distribution rates in 2009 in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39 (2009). The Department docketed the instant matter as D.P.U. 15-155, and suspended the effective date of the proposed rate increase until October 1, 2016, to investigate the propriety of the Company's petition.

MECo and Nantucket Electric are regulated investor-owned public utilities incorporated in Massachusetts (Exh. NG-MLR-1, at 23). Both companies operate as wholly owned subsidiaries of National Grid USA, which is an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales (Exh. NG-MLR-1, at 23).[1] National Grid is engaged in the retail distribution and sale of electricity across a Massachusetts service territory that serves approximately 1.3 million customers in 172 cities and towns (Exh. NG-MLR-1, at 23).

In the instant filing, the Company seeks a combined increase in base distribution rate revenues of $201.9 million (Exh. NG-RRP-2, at 1 (Rev. 3)).[2] The Company contends that its

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[1] National Grid USA also owns affiliated electric and gas distribution companies operating in Rhode Island and New York, while National Grid plc owns and operates electricity transmission, gas transmission and distribution networks in the United Kingdom (Exh. NG-MLR-1, at 23).

[2] On September 12, 2016, the Company advised the Department of the need to file amended Annual Returns for calendar years 2014 and 2015 to correct a purported error

petition also includes a $68.7 million decrease in revenues recovered in charges outside of base rates (Exh. NG-RRP-2, at 1 (Rev. 3)). Thus, the Company claims that its petition requests a net increase in annual delivery revenues of $133.2 million, or an approximately 20.3 percent increase in current annual delivery revenues (Exh. NG-RRP-2, at 1 (Rev. 3)).

As part of this filing, National Grid also seeks to continue, with several proposed modifications, its capital investment recovery mechanism ("CapEx"), which was approved in D.P.U. 09-39 and permits the Company to recover the revenue requirement associated with incremental capital investments. Further, National Grid seeks to continue, with several proposed modifications, its storm contingency fund, which originally was approved in New England Electric System, D.T.E. 99-47 (2000) and permits the Company to recover costs associated with certain storm-restoration activities. In addition, the Company offers several rate design-related proposals and a tariff intended to recover incremental property tax expense. The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015 (Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).

II. PROCEDURAL HISTORY

On November 16, 2015, the Attorney General of the Commonwealth of Massachusetts filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). On December 1, 2015, the

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regarding the recording of plant in service for fiscal years ending March 31, 2013 through 2016 (Cover Letter at 1, dated September 12, 2016). According to National Grid, now that the costs are correctly recorded, the Company will experience a net increase to operating expense of approximately $200,000 annually that will not be reflected in new distribution rates set in this proceeding (Cover Letter at 1). The Company does not seek to incorporate into the record in the instant case these amended Annual Returns, or the corrected recording of plant and expenses (Cover Letter at 1). Nevertheless, the Department finds that the Company's filing is extra-record material to which we give no probative weight. The Department will not consider these materials in evaluating the Company's instant petition for a base rate increase.

Department granted full party status to the Department of Energy Resources ("DOER") and the Low-Income Weatherization and Fuel Assistance Program Network ("Low Income Network"), limited participant status to PowerOptions, Inc., and joint limited participant status to NSTAR Electric Company, NSTAR Gas Company and Western Massachusetts Electric Company, together doing business as Eversource Energy. On December 10, 2015, the Department granted limited participant status to Solar Energy Industries Association. The following day, the Department granted limited participant status separately to The Berkshire Gas Company, and jointly to The Energy Consortium ("TEC") and Associated Industries of Massachusetts ("AIM"). On December 14, 2015, the Department granted limited participant status to The Alliance for Solar Choice. On December 17, 2015, the Department granted limited participant status to Brightergy, LLC.

On January 14, 2016, the Department granted limited intervenor status to Acadia Center; Vote Solar; Direct Energy Business, LLC, Direct Energy Services, LLC, and Astrum Solar, Inc. d/b/a Direct Energy Solar (collectively as "Direct Solar"); Energy Freedom Coalition of America, LLC ("EFCA"); and Northeast Clean Energy Council, Inc. ("NECEC"). See Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, Interlocutory Order (January 14, 2016).

Pursuant to notice duly issued, the Department held five public hearings in the Company's service territory: (1) in Brockton on March 15, 2016; (2) in Nantucket on March 21, 2016; (3) in Worcester on March 30, 2016; (4) in Great Barrington on April 4, 2016; and (5) in Lawrence on April 6, 2016. The Department also received written comments from public officials and several National Grid ratepayers.

The Department held 15 days of evidentiary hearings from May 2, 2016, through May 26, 2016. In support of the Company's filing, the following witnesses, all of whom are employed by National Grid USA Service Company, Inc. ("NGSC"), provided testimony: (1) Marcy L. Reed, president – Massachusetts; (2) Michael D. Laflamme, vice president, regulation and pricing – New England; (3) Margaret H. Kinsman, director of revenue requirements group – New England; (4) Maureen P. Heaphy, vice president of compensation, benefits and pensions; (5) James H. Patterson, Jr., director of network strategy – New England; (6) Stefan Nagy, analyst, program strategy; (7) John E. Walter, principal engineer, outdoor lighting and attachments group; (8) Jeanne A. Lloyd, principal program manager (electric pricing), regulation and pricing group – New England; (9) Peter T. Zschokke, director, regulatory strategy; (10) Scott M. McCabe, manager (electric pricing), regulation and pricing group – New England; (11) Timothy Roughan, director, energy/environmental policy; (12) Daniel J. DeMauro, Jr., director, IS Regulatory Compliance; (13) David H. Campbell, vice president, corporate finance; (14) Christopher P. Murphy, acting vice president, chief information officer; (15) Ryan Moe, senior specialist for vegetation strategy; (16) Daniel Bunszell, vice president, electric operations – New England; (17) Gladys Sarji, customer satisfaction and regulatory compliance; (18) Nancy Concemi, director, New England call center; and (19) John B. Currie, director, revenue and regulation – New England. In addition to NGSC personnel, the following outside consultants provided testimony on behalf of National Grid: (1) Robert B. Hevert, managing partner, Sussex Economic Advisors; (2) Ronald E. White, president, Foster Associates Consultants, LLC; (3) Howard Gorman, president, HSG Group, Inc.; and (4) Wayne S. Watkins, Pro Unlimited, Inc.

The Attorney General sponsored the testimony of the following witnesses:[3] (1) J. Randall Woolridge, Ph.D., professor of finance, Pennsylvania State University; (2) David J. Effron, consultant, Berkshire Consulting Services; (3) Donna Ramas, principal, Ramas Regulatory Consulting, LLC; (4) Timothy Newhard, analyst, Attorney General's Office of Ratepayer Advocacy; (5) Kyle Connors, analyst, Attorney General's Office of Ratepayer Advocacy; (6) Daniel O'Neill, president, O'Neill Management Consulting; (7) Charles Fijnvandraat, principal, Fijnvandraat Consulting Group; (8) Scott Rubin, consultant; and (9) William Dunkel, principal, William Dunkel and Associates.

The Low Income Network sponsored the testimony of John G. Howat, senior policy analyst, National Consumer Law Center, and Marina Levy, research assistant, National Consumer Law Center. Acadia Center sponsored the testimony of Abigail Anthony, Ph.D., director, grid modernization and utility reform, Acadia Center. Direct Energy sponsored the testimony of Frank Lacey, principal, Electric Advisors Consulting. EFCA sponsored the testimony of Tim Woolf, vice president, Synapse Energy Economics, Inc., and Melissa Whited, senior associate, Synapse Energy Economics, Inc. NECEC sponsored the testimony of R. Thomas Beach, principal consultant, Crossborder Energy. Finally, Vote Solar sponsored the testimony of Nathan Phelps, program manager, distributed generation regulatory policy, Vote Solar.

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[3] On December 15, 2015, the Department approved the Attorney General's retention of experts and consultants at a cost of $250,000, pursuant to G.L. c. 12, § 11E(b). See D.P.U. 15-155, Order on Attorney General Retention of Experts and Consultants (2015).

On June 17, 2016, the Department received initial briefs/comments from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, NSTAR Electric Company and Western Massachusetts Electric Company (collectively as "Eversource") and Vote Solar. National Grid submitted its initial brief on July 1, 2016.

On July 18, 2016, the Department received reply briefs from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, Vote Solar, PowerOptions, Inc., and, collectively, from TEC and AIM. The Company submitted its reply brief on July 25, 2016. The evidentiary record consists of more than 3800 exhibits and responses to 97 record requests.

III. NATIONAL GRID'S USE OF A SPLIT TEST YEAR

A. Introduction

The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015, a non-calendar or "split" test year (see Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).[4] Non-calendar test years have, on occasion, been accepted by the Department – most recently for water companies. See, e.g., Plymouth Water Company, D.P.U. 14-120, at 16 (2015); Milford Water Company, D.P.U. 12-86, at 1 (2013); Colonial Water Company, D.P.U. 11-20 (2011); Massachusetts-American Water Company, D.T.E. 00-105 (2001). As discussed in further detail below, the Department recently expressed its strong preference for a calendar year test year and noted that any company that seeks to rely on a split test year faces a

[4] A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. NSTAR Gas Company, D.P.U. 14-150, at 45, n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar test year or a split test year, comprises a period of twelve consecutive calendar months.

high burden to demonstrate as a threshold matter that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16 & n.11.

In support of its split test year filing, National Grid retained the independent accounting firm of PricewaterhouseCoopers, LLC ("PwC") to review the Company's operations and verify the accuracy of its non-calendar year test year financial data (Exhs. NG-RRP-1, at 6-7; NG-RRP-3).[5] PwC's review was performed under the attestation standards of the American Institute of Certified Public Accountants (Exh. NG-RRP-3, at 4). On October 30, 2015, PwC issued a report ("PwC Report") of its findings, which the Company submitted as part of the initial filing in this case (Exh. NG-RRP-3).

The scope of PwC's examination encompassed transactions recorded by the Company and NGSC (Exh. NG-RRP-3, at 4). PwC reviewed selected transactions that occurred during the test year in order to form an opinion on the accuracy of those transactions (Exh. NG-RRP-3, at 4). The transactions reviewed included vendor costs, labor costs and employee expense costs (Exh. NG-RRP-3, at 5).[6] PwC also examined general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 5). The PwC Report describes the sampling method used for each cost area (Exh. NG-RRP-3, at 5). The PwC Report also

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[5] The Company does not seek inclusion of the costs incurred for this review in this proceeding (Exhs. DPU-4-9; DPU-4-10; AG-15-1, at 2 (corrected)).

[6] For example, PWC performed the following tests with respect to vendor costs: (1) compare the cost recorded in the Company's ledger to the underlying vendor support such as an invoice or similar document; (2) review the underlying vendor information for the details of the services performed and identify whether services relate to the entity to which they were charged; and (3) review the underlying vendor information for the details of the services performed and identify whether the services were performed in support of the capital program (Exh. NG-RRP-3, at 6).

describes the testing procedures performed to ensure that costs were incurred, accurately calculated to reflect the underlying transaction, allocated to the correct operating company (where applicable), properly allocated among capital and expense (where applicable), and consistent with Company policy (Exh. NG-RRP-3, at 6). PwC examined, on a test basis, evidence supporting management's assertions regarding costs and performed other such procedures as PwC considered necessary under the circumstances (Exh. NG-RRP-3, at 27, 46). PwC concluded that the selected costs, in all material respects, were accurate (Exh. NG-RRP-3, at 27, 46).

B. Positions of the Parties

1. Attorney General

The Attorney General submits that because the Department establishes a utility's cost of service using test year data, and that the resulting distribution rates may be in effect for five years or more, a utility's test year financial information must be "accurate, verifiable, and verified" (Attorney General Brief at 8). Further, the Attorney General contends that the use of a spilt test year, rather than a calendar year, is problematic because it does not conform to the annual reporting periods or requirements set forth by the Department, the Federal Energy Regulatory Commission ("FERC"), and the Securities and Exchange Commission (Attorney General Brief at 8). She asserts that in the instant case, because National Grid chose to file its base rate case using a split test year, the Company must comply with the directives set forth in D.P.U. 14-120 to ensure that the record contains reliable and verifiable financial information (Attorney General Brief at 9-10).

In this regard, the Attorney General argues that National Grid failed to comply with the split test year filing requirements set forth in D.P.U. 14-120, because the Company: (1) failed to show that its test year account balances tie back to its Annual Returns to the Department;[7] and (2) failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9).[8] With respect to the first point, the Attorney General contends that the Company's requested rate increase is based on unverified worksheets (Attorney General Brief at 9). Further, the Attorney General claims that the PwC Report does not support the notion that the Company's account balances tie back to the Annual Return (Attorney General Reply Brief at 5). The Attorney General asserts that because a calendar year test year ties back to a company's Annual Return, the same level of verification is required for a split test year filing (Attorney General Reply Brief at 5). According to the Attorney General, the Department cannot on its own verify the accuracy of the Company's test year data and instead an

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7 Electric distribution companies, such as National Grid, must file an Annual Return with the Department annually on or before March 31. G.L. c. 164, § 83; 220 C.M.R. § 79.00, Introduction. The Annual Return includes the FERC Form 1 prescribed by FERC. 220 C.M.R. § 79.04(1). The FERC Form 1 presents financial and other operating data based on a calendar year ending December 31. 18 C.F.R. § 141.1(b)(2). The use of a calendar test year ensures that test year amounts tie back to the amounts included in the Annual Returns, and offers a level of assurance that the amounts have been properly recorded and are generally available for review. D.P.U. 14-120, at 11.

8 As explained by the American Institute of Certified Public Accountants ("AICPA"), an unqualified opinion presented in a report on the audit of financial statements states that the financial statements present fairly, in all material respects, the financial position, results of operations, and cash flows of the entity in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508.10, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf.

unqualified opinion letter is necessary for such verification (Attorney General Reply Brief at 3, 5, citing D.P.U. 14-120 at 11 & 16, n.11).

With respect to the audit requirement, the Attorney General argues that the Company's financial records were simply reviewed by an independent third party (i.e., PwC) and not audited as required by the Department in D.P.U. 14-120 (Attorney General Brief at 9, n.5, citing Exh. NG-RRP-1, at 6). In this regard, the Attorney General argues that PwC's review and subsequent report does not equate to an unqualified opinion letter from an independent auditor attesting to the accuracy of the financial information used to develop the cost of service in this case (Attorney General Brief at 9; Attorney General Reply Brief at 5). Further, the Attorney General rejects any notion that PwC's review of the Company's financial information was more thorough than a financial audit (Attorney General Reply Brief at 5). Thus, the Attorney General asserts that the Company has failed to meet its burden to provide an adequate record sufficient to enable the Department to conduct a meaningful review (Attorney General Reply Brief at 3, citing Town of Hingham v. Dep't. of Telecom. and Energy, 433 Mass. 198, 213-214 (2001)).[9]

Based on the above considerations, the Attorney General asserts that the Department should consider as a factor in setting National Grid's allowed rate of return, the Company's

[9] In particular, the Attorney General identifies three areas where she argues that a financial audit could have prevented the submission of inaccurate data to the Department: (1) the Company's purported overstatement of its depreciation expense caused by the inclusion of $100 million in plant retirements in the test year-end plant balance; (2) the Company's purported overstatement of net plant due to the failure to record $26 million in salvage; and (3) the Company's purported omission of certain project reports relating to plant additions (Attorney General Reply Brief at 4, citing Exhs. AG-18-19; AG-30-1, Att.; RR-AG-28). These issues are discussed in Sections III and VIII.E below. According to the Attorney General, a proper audit likely would have revealed additional significant inaccuracies that would be highly relevant to this proceeding (Attorney General Reply Brief at 4).

failure to meet the directives of D.P.U. 14-120 in using a split test year. Specifically, the Attorney General recommends that the Department should set the Company's allowed return on equity ("ROE") at the lowest end of the range of reasonableness (Attorney General Brief at 10, citing Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 231 (2002); Attorney General Reply Brief at 6).

2. Company

National Grid argues that it prepared its filing in compliance with the directives set forth in D.P.U. 14-120 (Company Brief at 9, citing Exh. NG-RRP-1, at 6-7). First, the Company argues that it developed financial statements that directly tie to the Company's 2014 Annual Return and to data submitted to FERC on FERC Forms 1 and 3-Q,[10] which are signed and sworn to by an officer of the Company (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). More specifically, the Company argues that these financial statements incorporate data submitted to FERC on FERC Form 1 for the calendar year 2014, which comprise the first six months of the test year, and FERC Form 3-Q for the year to date periods ending June 30, 2014 and June 30, 2015 (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). The Company contends that these financial statements provide the Department with a direct tie to data included in the Company's 2014 Annual Return and allow for a meaningful year-to-year comparison of twelve months of data to the annual data provided in the Annual Returns (Company Brief at 9,

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[10] FERC Form 3-Q presents financial and operating data on a calendar quarter basis, with a FERC Form 3-Q filed for each calendar quarter. 18 C.F.R. § 260.300. The Department does not require companies to submit their FERC Form 3-Q.

citing Exh. NG-RRP-1, at 6-7). The Company asserts that the Attorney General has not raised any specific instances of how these financial statements fail to tie back to the 2014 Annual Return, FERC Form 1 or FERC Form 3-Q (Company Brief at 14).

Second, National Grid argues that the PwC Report provides a solid foundation for the Department to review and analyze the Company's financial records used to develop the cost of service because it is an extensive third-party review of the test year data designed to verify data integrity and accuracy (Company Brief at 9, 15, citing Exhs. NG-RRP-1, at 6-11; NG-RRP-3). According to National Grid, there is no requirement set forth in D.P.U. 14-120 that the test year data is to be included in a routine annual audit or that the Company needs to obtain an unqualified opinion (Company Reply Brief at 13). Instead, the Company argues that D.P.U. 14-120 requires a showing that the test year amounts have been "properly audited," and that the PwC Report is sufficient to meet that requirement (Company Reply Brief at 13). In this regard, the Company asserts that PwC's review: (1) was performed under appropriate industry standards; and (2) was more thorough than the Company's annual financial audit conducted by PwC, particularly in relation to the specific financial data forming the cost of service in this proceeding (Company Brief at 10-11, 15, citing Exhs. NG-RRP-1, at 6-7; NG-RRP-3, at 4-5; AG-15-1, at 8, 9 (Corrected); Tr. 9, at 1399-1400, 1522-1523; Company Reply Brief at 13).

According to the Company, the PwC Report shows that: (1) the costs charged to the operating companies from the service companies were recorded accurately; (2) on a net basis, the costs were allocated appropriately to the various operating companies, consistent with the appropriate cost allocation manual; (3) the findings associated with the cost data provided in the scope of testing were not material to the service companies involved or to any one business unit;

and (4) there were no other pertinent facts identified during the review process indicating that the cost should be allocated differently (Company Brief at 12, citing Exhs. NG-RRP-3; AG-15-2, at 10 (Supp.)). The Company asserts that there is no evidence to suggest that a different type of audit would have produced different results (Company Reply Brief at 13-14).

Based on the foregoing, National Grid argues that the PwC Report substantiates the Company's use of a split test year in this proceeding and meets the threshold requirements set forth by the Department in D.P.U. 14-120 (Company Brief at 13). Thus, the Company asserts that the Department should find that the Company has met its burden with respect to using a split test year, and it should reject the Attorney General's recommendation that an adjustment to the allowed rate of return is warranted (Company Brief at 13, 16; Company Reply Brief at 15-16).

C. Analysis and Findings

1. Introduction

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45; D.P.U. 14-120, at 12, 16; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone and Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). See also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to G.L. c. 164, § 94 ("§ 94"), the Department examines a test year on the basis that

the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 146 (2016); citing D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45, n. 26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978).

As noted above, the Department has expressed strong preference for a test year cost of service based on a calendar year as opposed to a split test year. D.P.U. 14-120, at 12, 16; see also D.P.U. 14-150, at 45, n.26. Although the Department has, on occasion, accepted a non-calendar test year, see D.P.U. 14-120, at 10, 16; D.P.U. 12-86, at 1; D.P.U. 11-20; D.T.E. 00-105, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; see AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test year amounts associated with a split test year will not tie back to

amounts included in the Annual Returns submitted to the Department, which are prepared on a calendar-year basis. D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test year may create an improper incentive for utilities to book expenses into a certain time period for purposes of creating an inflated test year expense. D.P.U. 14-120, at 11. Another complication associated with use of split test years involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate setting process, may result in distorted measurement of net operations. D.P.U. 14-120, at 11; see The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

It also is well established that the burden is with a company to satisfy the Department that the company's proposal will result in just and reasonable rates. D.P.U. 14-120, at 11-12; Boston Gas Company, D.T.E. 03-40, at 52, n.31 (2003), citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993); Blackstone Gas Company, D.P.U. 19579, at 2-3 (1978).[11] Therefore, given the importance of the concerns discussed above and their significance for ratepayers, the Department affirms its very clear preference to use an historic calendar year test year to establish rates. D.P.U. 14-120, at 11-12.

As we noted in D.P.U. 14-120, at 12, any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and

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[11] That the burden of proof is always with those who take the affirmative in pleading is a long-held tenet in Massachusetts jurisprudence. Phelps v. Hartwell, 1 Mass. 71, 73 (1804).

reasonable. Specifically, any company that seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976). Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

> (1) of how its test year account balances tie back to the account balances as reported in the Annual Returns;
>
> (2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;
>
> (3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and
>
> (4) that the company has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances.

D.P.U. 14-120, at 16 n.11.

2. Discussion

As noted above, the Attorney General's challenge to the propriety of National Grid's reliance on a split test year rests on two main arguments: (1) that the Company failed to show that its test year account balances tie back to the Annual Return to the Department; and (2) that the Company failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9). However, we will address all four split test year threshold requirements set forth in D.P.U. 14-120.

First, the Company provided audited financial statements for the fiscal year ending March 31, 2015 (Exh AG-1-2, Att. 3 (3g) & (4g)).[12] While the Company's audited financial statements are not prepared using the same twelve-month period as the test year, the Department finds such statements helpful in ensuring that the Company's test year account balances have been verified, especially given that nine of the twelve months were the subject of the audit of the fiscal year ended March 31, 2015 (Exh. AG-1-2, Att. 3 (3g), (4g); Tr. 9, at 1397). The Company also provided the FERC Form 1s for the calendar years ending December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 4 (1f), (2f); RR-AG-29, Atts. 1, 3). Further, the Company provided its Annual Returns to the Department for calendar years ended December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 7 (1f), (2f); RR-AG-29, Atts. 2, 4). In addition, the Company provided FERC Form 1 financial statements containing financial information for the twelve months ended June 30, 2015 (Exhs. NG-RRP-1 at 6; WP-NG-RRP-1(a), (b), (c)). Based on our review of this information, we find that it is possible, though not easily discernible, to tie the Company's test year account balances back to the account balances as reported in the Annual Returns. See D.P.U. 14-120, at 16 n.11.

Next, the Company provided audited financial statements for the fiscal years ended 2009 through 2014 (Exh. AG-1-2, Atts. 3 (3a) through (4g)). In addition, the Company provided the

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12 A financial audit is an examination of historical financial statements performed in accordance with generally accepted auditing standards, with a report issued on the results stating an opinion whether the financial statements present the audited entity's financial position, results of operations, and cash flows in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508, n.1, §§ 508.07.08, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf; see also D.P.U. 14-120, at 15.

FERC Form 1s for calendar years ending December 31, 2009 and December 31, 2013 (Exh. AG-1-2, Atts. 4 (1a) through (2f)). We conclude that this information, when reviewed in conjunction with the test year data and the PwC Report (as discussed in greater detail below), allows for a meaningful review of year-to-year changes in expense levels in order to determine whether the Company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability. See D.P.U. 14-120, at 16 n.11.

Further, we find that the test year amounts have been properly audited and are available for review. In particular, we are not persuaded by the Attorney General's argument that the Company's financial statements are unreliable because they lack verification through an unqualified opinion letter. While the PwC Report does not represent an unqualified opinion letter, we find that it does provide an independent and extensive review of the Company's test year cost of service data that is sufficient to make the D.P.U. 14-120 threshold showing. As noted, the record contains several of the Company's annual financial audits (Exh. AG-1-2, Att. 3 (3g) & (4g); Tr. 9 at 1397). As discussed below, in this instance PwC's review was, in a number of ways, likely more extensive than the scope of these financial audits.

The record shows that PwC performed an extensive review of over 4,500 individual invoice transactions relevant to the Company's cost of service in this case, including vendor costs, labor costs, employee expense costs, and general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 4-5; Tr. 9, at 1522-1523). Thus, PwC's review encompassed a wide range of expense activity on a transactional level, as opposed

to a review of a smaller sample population of transactions, which is typically done in a financial audit (Exh. NG-RRP-1, at 8-9; Tr. 9, at 1399-1400).

For each cost area, the PwC Report clearly describes the methods used to select which transactions were reviewed (Exh. NG-RRP-3, at 5). Further, the PwC Report describes the extensive testing procedures performed to verify the propriety of costs incurred by the Company in the split test year (Exhs. NG-RRP-3, at 6; NG-RRP-1, at 7-8). The record shows that for each of the charges it reviewed, PwC examined relevant supporting documentation, such as invoices, expense reports, receipts, time sheets and other documents (Exhs. NG-RRP-3, at 6; AG-15-1, at 8 (corrected)). Further, for each charge, PwC confirmed that it was: (1) incurred during the split test year; (2) accurate; (3) properly allocated to the correct company or companies (where applicable) and to expense or capital (where applicable); (4) properly allocated in accordance with National Grid USA's Cost Allocation Policies and Procedures Manual ("CAM"); and (5) not accounted for as below-the-line for ratemaking purposes (Exhs. NG-RRP-1, at 7-8; NG-RRP-3, at 6, 30; AG-15-1, at 8 (corrected)). Thus, PwC's review was likely more extensive for ratemaking purposes than a financial audit, which tends to focus on whether the Company has properly maintained its financial records consistent with accounting requirements. See D.P.U. 14-120, at 15. If PwC found that there was inadequate support for a particular charge or if it had questions regarding a particular charge, it undertook a further examination of the charge, including requesting additional documentation to support the charge and, frequently, following up with the business process owner to understand the allocation related to a particular charge (Exh. NG-RRP-1, at 8). In instances where the Company could not provide sufficient support for the charge or a clear explanation of the charge allocation, PwC flagged the charge as

a proposed adjustment or considered whether a different bill pool or direct charge would have been more appropriate to use as a basis for cost allocation (Exh. NG-RRP-1, at 8). Based on the quality and comprehensiveness of PwC's review, we find that there is a sufficient basis to conclude that the Company's test year amounts have been properly "audited" in order to satisfy the split test year threshold requirement as set forth in D.P.U. 14-120. D.P.U. 14-120, at 16 n.11.[13]

Finally, PwC reviewed beginning and end-of-year accruals in order to review the allocation of costs among monthly periods during the split test year (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). In particular, PwC identified all vendor cost invoices that had service dates prior to the beginning of the test year and compared the amount recognized as a cost in the test year to the amount accrued at the beginning of the test year and reversed during the test year, in order to test the elimination of out-of-period charges in the test year data (Exh. NG-RRP-3, at 14, 24). PwC then reviewed accruals recorded at the end of the test year and compared the amounts of supporting calculations (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). Further, PwC reviewed a number of invoices received after the test year to determine if those invoices related to services performed in the test year and, for those invoices that did, compared the

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[13] In light of this finding, we need not address the Attorney General's argument that the Department cannot, on its own, verify the Company's test year data. Further, we are not persuaded by the Attorney General's argument that use of a calendar year test year and an unqualified opinion letter would have prevented the Company's purported overstatement of depreciation and net plant, or its alleged failure to file certain project reports at the outset of the case (Attorney General Reply Brief at 4). While we expect National Grid to present a filing that is as complete and accurate as possible, these concerns are not sufficient to call into question the reviewability of the Company's entire rate request. Instead, the Department will determine the appropriate ratemaking treatment of these items, under the circumstances identified by the Attorney General, in the relevant sections of this Order.

invoice to the accruals at the end of the test year to determine an appropriate adjustment to test year costs (Exh. NG-RRP-1, at 9).[14] Based on these findings, we conclude that through the PwC Report, the Company has shown that it has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances. D.P.U. 14-120, at 16 n.11.

3. Conclusion

Based on the above considerations, the Department finds that National Grid has satisfied the split test year threshold requirements set forth in D.P.U. 14-120 and has demonstrated by clear and convincing evidence that its financial data is reviewable and reliable and represents a full accounting of the Company's operations for the test year period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate National Grid's filing based on a test year for the twelve months ending June 30, 2015. Further, we decline to make any specific adjustment to the Company's ROE due to the use of a split test year, as recommended by the Attorney General. However, while we accept PwC's findings for purposes of determining the accuracy and reviewability of the financial information submitted by the Company in this case, we do not accept the PwC Report as a proxy for establishing the appropriate cost of service in this case. As we have noted in prior cases, while audited financial statements are of considerable assistance in the ratemaking process, an audit does not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded

[14] For this aspect of its examination and verification process, PwC reported a net decrease to test year costs for the Company in the amount of $1,094,601 (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 7, 24). The Company states that this amount was offset by findings in other elements of PwC's review (Exh. NG-RRP-1, at 9).

to such costs. D.P.U. 14-120, at 15; citing Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240, Introductory Letter (May 19, 1941); Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997). The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

Finally, we emphasis that our findings here are limited to the specific facts and circumstances of this case and in no way change the Department's clear preference for companies to use a calendar year test year as the norm. D.P.U. 14-120, at 16. We reiterate that any company that seeks to rely on a split test year must, at a minimum threshold level, make a prima facie showing by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Failure to make such a robust showing will result in dismissal of the company's rate proceeding.

IV. REVENUE DECOUPLING MECHANISM

A. Introduction

In D.P.U. 07-50-A at 4-5, 32, 81-82, the Department directed each electric and gas distribution company to propose a full revenue decoupling mechanism ("RDM") in its future base distribution rate proceedings. The Department stated that the objective of revenue decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the companies with policy objectives

regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources." D.P.U. 07-50-A at 31-32.

In directing electric distribution companies to adopt full revenue decoupling, the Department acknowledged that decoupling would remove the opportunity to earn additional revenue from growth in sales between base distribution rate proceedings and further acknowledged that such revenue typically funded, among other things, increased operation and maintenance ("O&M") expenses as well as system reliability and capital investment projects. D.P.U. 07-50-A at 48, 87. Accordingly, the Department stated that it would consider company-specific proposals that account for the effects of increased capital investments and inflation on target revenue. D.P.U. 07-50-A at 49-50.[15]

The Department approved the Company's revenue decoupling provision in its last base distribution rate proceeding. D.P.U. 09-39, at 61-92. National Grid's current revenue decoupling tariff provision includes two components that operate in concert: (1) a traditional RDM reconciliation with full revenue decoupling; and (2) the Company's CapEx mechanism (Exh. NG-PP-1, at 82-83). In the RDM reconciliation, the annual target revenue ("ATR") set in the Company's base distribution rate proceeding is adjusted by the cumulative CapEx cost recovery for the upcoming year (Exh. NG-PP-1, at 83). The adjusted ATR is reconciled against billed base distribution revenue and CapEx factor revenue (Exh. NG-PP-1, at 83). The Company is authorized to collect up to three percent of total revenues through the resulting revenue decoupling adjustment factors ("RDAFs") (Exh. DPU-18-21, Att. at 5 (M.D.P.U. No. 1289,

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15 See Section VII.B for a discussion of the Company's proposal regarding capital investments.

Sheet 4, § V)). Each year's ATR is greater than the prior year's ATR because the CapEx cost recovery cumulates year-over-year from additional capital investments (Exh. NG-PP-1, at 83). Additionally, the total amount that the Company seeks recovery of through the RDM will eventually reach and exceed the three-percent cap because National Grid measures the entire annual CapEx cost recovery against the three-percent cap, instead of the change in CapEx cost recovery from year-to-year (Exh. NG-PP-1, at 85-86). Moreover, the current revenue decoupling provision does not permit the Company to apply a revenue cap separately to its RDM reconciliation component and to its CapEx recovery component (Exh. NG-PP-1, at 85). Instead, the three-percent cap is compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86).

B. Company Proposal

The Company proposes to remove the CapEx cost recovery from the current revenue decoupling provision tariff and move this component to a separate tariff and operate it as an independent cost recovery mechanism (see Section V) (Exhs. NG-PP-1, at 81; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).[16] The Company proposes that the remaining components of the revenue decoupling provision will govern the operation of National Grid's traditional RDM reconciliation.

In particular, the Company proposes to continue the traditional RDM reconciliation component in its revenue decoupling provision, with updated target revenues set at the proposed base rate revenue requirement for each customer class and modifications to the revenue cap

[16] The Company proposes to apply a separate revenue cap to the independent CapEx recovery component (Exhs. NG-PP-1, at 81-82; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).

(Exhs. NG-PP-1, at 81; NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). National Grid's current and proposed ATRs by rate class are shown in the following table:

Rate Class	**Current ATR**	**Proposed ATR**
Rate R-1/R-2	$306,532,557	$451,769,965
Rate R-4	$347,350	$599,269
Rate G-1	$97,267,709	$97,070,193
Rate G-2	$56,298,775	$91,441,732
Rate G-3	$106,895,246	$140,607,030
Street lighting	$20,525,360	$17,639,752
Total	$587,866,996	$799,127,941

(Exhs. NG-PP-23, at 181 (proposed M.D.P.U. No. 1278, at sheet 2); NG-PP-24, at 259; DPU-18-21, Att. at 4). National Grid proposes to submit annual RDM filings by January 15 to reconcile its actual revenues to the ATR pursuant to its revenue decoupling provision, with the RDAFs to take effect on March 1 (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

However, the Company proposes two modifications to the RDM cap: (1) the revenue that forms the basis for the RDM cap will reflect total revenue and include an adjustment for electric supply for those customers who took service from a competitive supplier during the year; and (2) a three-percent cap will be applied to both under- and over-recoveries of the RDM reconciliation between billed revenue and ATR (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23).

Finally, in the Company's 2015 annual RDM reconciliation filing, the Department directed National Grid to adjust its ATR, not its distribution revenues, to account for the sale of street lighting assets, and the Company amended its revenue decoupling provision tariff accordingly (see Exh. DPU-18-21, Att. (M.D.P.U. No. 1289)). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136-A at 11 (January 21, 2016). The primary

revision to the revenue decoupling provision tariff was the addition of the "Streetlight Sales Adjustment" definition (Exh. DPU-18-21, Att. at 3 (M.D.P.U. No. 1289, at sheet 2)).[17]

C. Positions of the Parties

National Grid argues that the proposed modifications to its revenue decoupling provision align it with the operation of RDMs in place for other distribution utilities (Company Brief at 164).[18] No other party addressed the Company's proposed modifications to the traditional RDM reconciliation on brief.

D. Analysis and Findings

In Section V.D below, the Department allowed the Company to continue the operation of its CapEx mechanism in a separate tariff, with modifications, including its separation from the revenue decoupling provision and operation as a distinct reconciling mechanism. Thus, in this section we will address the Company's remaining proposed revisions to its traditional RDM reconciliation component of its current revenue decoupling provision.

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[17] According to the Company, "'Streetlight Sales Adjustment' shall mean the annual cumulative dollar adjustment to each year's ATR as a result of selling its streetlighting equipment pursuant to G.L. c. 164 § 34A subsequent to the effective date of new base distribution rates resulting from a general rate case. The Streetlight Sales Adjustment shall be a downward adjustment to each year's ATR and shall be calculated as the proceeds received by the Company from the sale of its streetlighting equipment multiplied by the avoided cost of no longer owning, operating, and maintaining such equipment, stated as a percentage, as determined by the Company's final streetlight revenue requirement. The Streetlight Sales Adjustment shall be set to zero and calculated for new streetlight sales effective with the subsequent implementation of new base distribution rates as provided for above. The Streetlight Sales Adjustment is pursuant to the Department's directive in D.P.U. 14-136-A" (Exh. DPU-18-21, Att. at 3).

[18] The Company does not specify whether these utilities are gas or electric utilities (Exh. NG-PP-1, at 84). However, the Company states that gas utility targeted infrastructure replacement programs demonstrate similar language on the application of revenue caps (Exh. NG-PP-1, at 84).

The Department has determined that a RDM must be consistent with our precedent related to rate continuity, fairness, and earnings stability. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50, at 12 (2007). The Department has found that the application of a revenue cap in the context of a RDM is consistent with this precedent. D.P.U. 14-150, at 20; Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 116 (2011). Moreover, the Department has previously stated that revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates. Western Massachusetts Electric Company, D.P.U. 10-70, at 45 (2011); D.P.U. 09-39, at 87.

The Company proposes two modifications to the RDM cap. First, the Department evaluates the Company's proposal to include an adjustment for electric supply for those customers who took service from a competitive supplier during the year. We find that this proposed adjustment is consistent with decoupling mechanisms in use by other utilities. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 24. Therefore, the Department accepts the Company's proposal.

Next, we address the proposed three-percent cap to be applied to the RDM reconciliation between billed revenue and ATR. The Company proposes to cap the total RDM reconciliation (excluding CapEx cost recovery) at three-percent of total revenues, including an adjustment for electric supply for those customers who took service from a competitive supplier during the year, and to apply the three-percent cap to both under- and over-recoveries of the RDM reconciliation balance (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23). In previously approving a three-percent cap in the Company's revenue decoupling

provision (which included CapEx cost recovery), the Department stated that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render the three-percent cap inappropriate. D.P.U. 09-39, at 88. The Department expressed that it may review and modify such a cap, as necessary, over the course of the Company's revenue decoupling adjustment filings. D.P.U. 09-39, at 88.

Although the Company's three-percent cap is consistent with the revenue decoupling provision approved in its previous base distribution rate proceeding, the three-percent cap was applied to an RDM adjustment that previously included a RDM reconciliation balance with an adjustment for CapEx cost recovery. D.P.U. 09-39, at 87-88. The three-percent cap was compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86). However, given that we have approved the continuation of the CapEx mechanism as a separate mechanism from the revenue decoupling tariff provision (see Section V.D below), it is now more appropriate to set National Grid's cap on the annual revenue decoupling adjustment at one-percent cap of total revenue. We conclude that a one-percent cap based on total revenues ensures continuity, fairness, and earnings stability. Any amount above the one-percent cap will be deferred with interest calculated at the customer deposit rate until there is sufficient room under a future cap to recover the deferral balance (Exhs. NG-PP-1, at 84; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

Additionally, the purpose of the one-percent cap is to protect customers from large revenue decoupling adjustments. D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. However, no such protection is necessary in the event of a decoupling adjustment credit.

D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. Accordingly, the Department declines to accept the Company's proposal to apply the revenue cap to over-recoveries of ATR, which would result in a credit to customers (see Exh. DPU-18-23). The Department finds that the one-percent revenue cap shall apply only to under-recoveries of ATR.

Based on the foregoing, the Department directs the Company to modify the language of its revenue decoupling provision tariff to include a revenue decoupling adjustment cap that is based on one-percent of total Company revenues from the previous calendar year. National Grid is also directed to include language in its revenue decoupling provision tariff that ensures that the revenue decoupling adjustment cap is applied only to under-recoveries to be collected from ratepayers in the RDAFs.

With respect to the ATRs proposed in this filing, we note that they are calculated from the revenue requirements proposed by the Company to be collected from each rate class (Exhs. NG-RRP-2, at 1 (Rev. 1); NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). As noted below in Schedule 1, the Department has approved a different revenue requirement than that proposed by the Company. As such, the Company is directed, in its compliance filing, to file new ATRs by rate class based on the revenue requirement for each rate class approved in this Order.

Further, in D.P.U. 14-136-A, the Department directed the Company to adjust its ATRs to account for the sale of street lighting assets. D.P.U. 14-136-A at 11. The Company added a definition to its revenue decoupling provision for "Streetlight Sales Adjustment" (see n.17 above) in compliance with that Order (Exh. DPU-18-21, Att. at 8). The Department directs the

Company in its compliance filing to include these tariff modifications, as approved in D.P.U. 14-136-A, in its revenue decoupling provision tariff.

Finally, the Department reiterates that the RDM allows companies to modify, on an annual basis, base distribution rates as a result of changes in sales in order to promote the efficient deployment of demand resources. D.P.U. 09-39, at 9, 62-63. Revenue decoupling was intended to provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future. D.P.U. 07-50-A at 1. Moreover, the Department noted that the conclusions reached in D.P.U. 07-50-A represented general statements of policy. D.P.U. 14-150, at 16-17; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-B, at 28-29 (2008).

The Department acknowledges that we have our own concerns about the appropriateness of including street lighting rate classes in a revenue decoupling provision. Currently, the Company does not offer energy efficiency programs directed towards street lighting, and street lighting use is not metered and, as such, distribution revenues are fixed (Tr. 6, at 805-806; Tr. 8, at 1201-1202). Additionally, revenue decoupling was not intended to compensate a company for the sale of street lighting assets. D.P.U. 14-136-A, at 10; see D.P.U. 07-50-A. In the Department's decoupling investigation, we did not contemplate this potential issue, and the model we adopted to decouple rates for all future ratemaking proceedings was silent on street lighting rate classes in RDM. D.P.U. 07-50-B at 26.

For these reasons, the Department expects to address the issue of street lighting rate classes included in the revenue decoupling provisions in a future proceeding. In this regard, the Department puts the Company, and all electric distribution companies, on notice that it has

concerns with the inclusion of street lighting rate classes in RDMs, and that we will consider removing street lighting rate classes from RDMs in each electric distribution company's next base distribution rate proceeding. Thus, as part of the initial filing in its next base distribution rate proceeding, each electric distribution company must address and provide justification for the continued inclusion of street lighting rate classes in each company's respective revenue decoupling provision.

V. CAPITAL INVESTMENT RECOVERY MECHANISM

A. Introduction

In the Company's last base rate case, the Department approved National Grid's revenue decoupling provision, which included a CapEx mechanism allowing the Company to recover an annual revenue requirement on incremental capital investments up to a $170 million cap (hereinafter referred to as the "investment cap"). D.P.U. 09-39, at 82.[19] In addition to the $170 million cap, the approved revenue decoupling provision includes a rate cap limiting the annual revenue decoupling adjustment (including the CapEx revenue requirement adjustment to the Annual Target Revenue ("ATR")) to three percent of total revenue (hereinafter referred to as the "rate cap"). D.P.U. 09-39, at 82, 87-88.

Incremental capital investment for each year since the CapEx mechanism commenced is defined as annual capital investment, less the Company's depreciation expense allowed in its last base rate proceeding (Exh. NG-RRP-1, at 54). National Grid calculates each investment vintage year's revenue requirement using an average rate base methodology, incorporating accumulated depreciation and accumulated deferred income taxes associated with that vintage year's

[19] A review of the Company's capital investments made between the date of the decision in D.P.U. 09-39 and the end of the test year in this case is discussed in Section VII.B below.

investments (Exh. NG-RRP-1, at 54). The CapEx mechanism does not allow for the recovery of the revenue requirement for the year of investment for each vintage year, and the Company recovers the revenue requirement for the second year of each vintage beginning March 1st of the subsequent year (Exh. NG-RRP-1, at 54).[20]

B. Company Proposal

National Grid proposes to continue its existing CapEx mechanism with several modifications, including changing its name to the capital investment recovery mechanism ("CIRM") (Exhs. NG-MLR-1, at 16; NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22). The Company proposes to: (1) separate the CIRM from the traditional RDM reconciliation, and operate the mechanisms under separate tariffs; (2) increase the annual investment cap on capital expenditures from $170 million to $285 million; (3) include property taxes in the computation of the CIRM revenue requirement; and (4) apply a one-percent rate cap to the change in annual revenue requirement in the CIRM (Exhs. NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22).

As set forth in great detail below, the Attorney General opposes all of the proposed modifications. Instead, the Attorney General recommends that the Department should eliminate the CIRM entirely, or, in the alternative, do the following: (1) maintain the investment cap at $170 million, or in the alternative, set the cap at $183 million; (2) limit the scope of capital investments eligible for recovery; (3) include metrics, goals, and/or reporting to provide accountability of customer benefits associated with the Company's capital investments, and to

[20] The Company's current CapEx mechanism, and proposed capital investment recovery mechanism, imposes a 14-month lag on the recovery of the second year revenue requirement for each vintage investment year (Exh. DPU-6-17).

verify that costs are reasonable; (4) include an O&M offset, representing the savings associated with the capital investments; and (5) adjust the rate of return in the CIRM downward to reflect risk reduction associated with the Company's recovery of capital investment with little to no regulatory lag (Exh. AG-DO-CF-1, at 8, 11-12, 18-20; Attorney General Brief at 88-94; Attorney General Brief at 49-53).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General initially recommends discontinuance of the CIRM (Attorney General Brief at 85). The Attorney General maintains that her recommended modifications are necessary to control costs and limit spending to projects that are necessary to provide safe and reliable service (Attorney General Reply Brief at 52, citing Exh. NG-JHP-1, at 29). The Attorney General's specific arguments in support of these positions are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Attorney General recommends elimination of the CIRM entirely (Attorney General Brief at 85). According to the Attorney General, the Department allows alternative regulatory mechanisms only in cases of "extraordinary circumstances," where a company has demonstrated its need to recover incremental costs associated with specific programs between base distribution rate cases (Attorney General Brief at 85, citing Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121-122, 132-133 (2010); D.P.U. 09-39, at 79-80, 82; Bay State Gas Company, D.P.U. 09-30, at 133-134 (2009)). The Attorney General

rejects any notion that the Company's investment needs are extraordinary, and she claims that many of these investments will be eligible for recovery through a separate recovery mechanism pending in the Grid Modernization Investigation, D.P.U. 15-120 (Attorney General Brief at 86, citing Company Brief at 97; Attorney General Reply Brief at 48, citing Exh. AG-DO-CF-1, at 12). Therefore, the Attorney General asserts that the Company failed to produce evidence of "extraordinary circumstances" to justify the continuation of the CIRM (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Moreover, the Attorney General argues that the Company is not in a unique position, nor is it under significant pressure to maintain a high degree of system reliability and resiliency, as it claims, because all utilities must invest in their systems for reliability (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 101; Attorney General Reply Brief at 47). Thus, the Attorney General argues that the Company's investment obligations are not extraordinary, but "standard operating procedure" (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Further, the Attorney General dismisses the Company's claim that the CIRM is necessary due to revenue decoupling (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 96-98). According to the Attorney General, the Department has previously rejected other companies' requests for a CIRM when those companies were unable to provide "compelling evidence of lost growth in sales" (Attorney General Brief at 86, citing Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 36 (2014); D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; D.P.U. 07-50-A at 50). In this regard, the Attorney General contends that revenue decoupling ensures the Company will be compensated for lost sales revenue associated with energy efficiency programs and distributed generation ("DG"), which the Company admits is

causing its sales forecast to show declining growth (Attorney General Brief at 86-87, citing Exh. DPU-6-14, at 2; Attorney General Reply Brief at 48).[21] Therefore, the Attorney General asserts that because revenue decoupling will not remove the Company's ability to retain additional revenue between its base rate proceedings, there is no need for an additional recovery mechanism. (Attorney General Brief at 87, citing D.P.U. 10-70, at 47).

Additionally, the Attorney General alleges that the Company is financially healthy and highly liquid, and therefore, there is no need for the CIRM (Attorney General Reply Brief at 48). According to the Attorney General, the Company was allowed $40 million in base distribution rates for income taxes in its last base rate proceeding, but because of tax benefits the Company has not and will not pay income taxes for many years (Attorney General Reply Brief at 48, n.18, citing D.P.U. 09-39, at 457; Exh. NG-RRP-2, at 2, 30). Moreover, the Attorney General contends that the Company had sufficient cash available to lend hundreds of millions of dollars to its affiliates through the National Grid USA money pool over the last two years (Attorney General Reply Brief at 48, n.2 citing Exh. AG-1 (National Grid USA Money Pool Report)).

The Attorney General also argues that the Department should consider National Grid's proposed CIRM in conjunction with the Company's other reconciling mechanisms (Attorney General Reply Brief at 48). According to the Attorney General, the Company charges ratepayers on an annual basis for the following: (1) pensions and post-retirement benefits other than pensions ("PBOP") costs; (2) storm costs; (3) energy efficiency program costs; and (4) wind energy contract remuneration (Attorney General Reply Brief at 49, citing Exh. NG-RRP-2, at 2-3). The Attorney General argues that approving the CIRM and allowing these other

[21] The Attorney General also notes that the Company receives compensation and incentives related to energy efficiency programs (Attorney General Reply Brief at 48).

reconciling mechanisms exposes ratepayers to an excessive share of risk (Attorney General Reply Brief at 49).

Finally, the Attorney General claims that the CIRM requires an annual prudency review and cost reconciliation, thereby adding to the Department's administrative burden (Attorney General Brief at 87). The Attorney General maintains that based on the Company's prior CIRM experience,[22] future prudency reviews will likely evolve into exhaustive investigations (Attorney General Brief at 87-88, citing docket D.P.U. 10-79; Exh. AG-DO-CF-1, at 35-56). For all these reasons, the Attorney General asserts that the Company's CIRM proposal is not in the best interest of ratepayers and should be discontinued (Attorney General Brief at 87-88; Attorney General Reply Brief at 48). As noted above, in the alternative, the Attorney General asserts that the Department should retain the current investment cap and make specific modifications to the Company's proposal, each of which are discussed below.

c. Investment Cap

The Attorney General argues that the CIRM "significantly reduces and potentially eliminates the important incentive that regulatory lag provides" to control costs because the Company is allowed to recover a return on and of its capital expenditures in the year that they are incurred (Attorney General Brief at 92, citing D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 50, citing D.P.U. 09-39, at 80-81). According to the Attorney General, the Department has found that in the absence of regulatory lag, a cap on the annual CIRM cost recovery would protect ratepayers from over-investment in capital infrastructure and still provide the Company

[22] The Attorney General claims that in National Grid's first CapEx investigation, the Company failed to provide project documentation in a timely manner and its filing ultimately lacked clear, cohesive, reviewable project documentation (Attorney General Brief at 88, citing Exh. AG-DO-CF-1, at 35-56).

with sufficient funds to ensure safe and reliable electric service (Attorney General Brief at 92, citing D.P.U. 09-39, at 81-82; Attorney General Reply Brief at 50). In this regard, the Attorney General contends that the Company budgeted for capital spending to align with the $170 million investment cap allowed by the Department when initially approving the CIRM (Attorney General Brief at 92, citing Exhs. DPU-6-7; DPU-18-5).[23] Thus, the Attorney General contends that the $170 million investment cap is an effective means of cost control, and National Grid may include plant additions above the investment cap in the rate base proposal in the Company's next base rate proceeding (Attorney General Brief at 92-93, citing D.P.U. 09-39, at 82-83). Further, she argues that increasing the investment cap will likely lead to a corresponding increase in unfettered capital spending, evident from the Company's capital investment forecast (Attorney General Brief at 92-93, citing Exh. AG-DO-CF-1, at 20; Attorney General Brief at 87, citing Exh. NG-JHP-1, at 29). For these reasons, the Attorney General recommends setting the investment cap at $170 million so as to balance the risk associated with the CIRM between shareholders and ratepayers (Attorney General Brief at 92, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 48, 49, 50, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80–81.).

In the alternative, if the Department decides to increase the investment cap from $170 million, the Attorney General argues that the Department should set the cap based on a representative level of historic spending, and not on forecasted spending (Attorney General Brief at 93; Attorney General Reply Brief at 50, citing D.P.U. 1580, at 13–17, 19; D.P.U. 136, at 3;

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[23] However, she also alleges that the $170 million investment cap has not prevented the Company from exceeding it (Attorney General Reply Brief at 50, citing RR-DPU-13, Att.).

D.P.U. 19992, at 2; D.P.U. 18204, at 4; D.P.U. 18210, at 2–3; D.P.U. 18264, at 2-4; Attorney General Reply Brief at 51).[24] According to the Attorney General, when the Department grants a capital recovery mechanism, it bases it on an average of historical expenditures, not on company projections. (Attorney General Reply Brief at 51, citing D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82). Therefore, the Attorney General asserts that the investment cap should be based on a five-year average of plant additions (excluding cost of removal), instead of a three-year average[25] that the Department used to establish the $170 million investment cap (Attorney General Brief at 93, citing D.P.U. 09-39, at 82; D.P.U. 15-80/D.P.U. 15-81, at 53). The Attorney General maintains that a five-year average of plant additions (excluding cost of removal) is more appropriate than a three-year average because the Company's plant additions in 2013 and 2015 were not representative of a typical year (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).[26] Further, the Attorney General maintains that a five-year average for plant additions of $183 million provides an appropriate balance of sufficient funding for the Company and ensuring safe and reliable service (Attorney General Brief at 93, citing RR-DPU-14; Attorney General Reply Brief at 49, 51).

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24 The Attorney General alleges that the Company's proposed $285 million cap is based on future projections (Attorney General Reply Brief at 50-51).

25 The Attorney General calculates the Company's three-year average of plant additions (excluding cost of removal) at $197 million (Attorney General Brief at 93, citing RR-DPU-9).

26 The Attorney General explains that the Company's spending in 2015 was significantly higher than the prior years (i.e., $259 million in 2015; $180 million in 2014; $151 million in 2013; and $139 million in 2012), and in 2013, storm restoration efforts and issues related to the SAP implementation affected the Company's plant additions (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).

d. Modifications to the CapEx/CIRM

i. Scope

The Attorney General recommends that the Department direct the Company to narrow the scope of its CIRM to a certain category of spending (Attorney General Brief at 88; 89-90; Attorney General Reply Brief at 48, 49-50, 51). According to the Attorney General, a capital cost recovery mechanism is most effective when it is targeted to provide specific improvements and goals, and allows interested parties to track the costs associated with specific investment activities (Attorney General Brief at 88, citing D.P.U. 10-70, at 47-50; D.P.U. 10-55, at 66). The Attorney General explains that capital cost recovery mechanisms used by other states are more narrow and targeted compared to the Company's CIRM, and these mechanisms recover specific capital costs such as solar, renewable energy, or smart grid investments (Attorney General Brief at 88-89, citing Exh. AG-DO-CF-1, at 10-11; Tr. 15, at 1601-1603, 1683; Attorney General Reply Brief at 48-49, citing Tr. 15, at 1683). Additionally, the Attorney General explains that Connecticut Light and Power's ("CL&P") capital cost recovery mechanism authorizes recovery of specific projects that improve storm hardening infrastructure, and in 2013, represented an annual revenue requirement of $34.9 million (Attorney General Brief at 89, citing RR-NG-2, at 1; Attorney General Reply Brief at 52). The Attorney General does not make a specific recommendation regarding a spending category to limit the scope of the Company's CIRM, but she acknowledges that the Company already recovers costs for solar investments, smart grid technologies, and storm-related costs separately from the CIRM and base rates (Attorney General Brief at 89, citing Exhs. NG-RRP-1, at 107-110; AG-DO-CF-1, at 12; Tr. 15, at 1683).

ii. Benefits

The Attorney General recommends that the CIRM include a mechanism to account for customer benefits achieved in conjunction with annual capital spending (Attorney General Brief at 90, citing Exh. AG-DO-CF-1, at 13). The Attorney General claims that there is no evidence that National Grid's proposed CIRM will contribute to cost-effective, safe, and reliable service (Attorney General Brief at 90). For example, the Attorney General explains that the budget for "Asset Condition," which covers the replacement of assets the Company believes will fail, is forecasted to increase 116 percent over historical spending (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19-20). The Attorney General expects that this increase in spending would lead to a decrease or leveling out in the budget for "Damage/Failure," which covers the costs for the replacement of failed assets (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19). The Attorney General claims, however, that the Company's "Damage/Failure" budget category forecast for 2017-2019 increases 32 percent over historical spending (Attorney General Brief at 91, citing Exh. AG-7-5, Att.). From this data, the Attorney General contends that the Company is planning to replace assets with a low probability of failure to increase the costs recovered through the CIRM, thereby providing the Company with an opportunity for "gold-plating" (Attorney General Brief at 90-91, citing Exh. AG-7-5, Att.).

Further, the Attorney General maintains that other utilities include reports on the effectiveness of their capital cost recovery mechanisms (e.g., TIRF programs[27] include reports on leaks and CL&P provides data on system resiliency) (Attorney General Brief at 91,

[27] TIRF refers to targeted infrastructure recovery factor programs that are designed to allow for annual recovery by gas distribution companies of the revenue requirement associated with incremental investment for the replacement of leak-prone infrastructure. See, e.g., D.P.U. 09-30, at 121.

citing Exh. AG-DO-CF-1, at 13, 16; RR-NG-2, Att. 2, at 11-12). The Attorney General asserts that there should be greater accountability in the Company's CIRM mechanism because it is much broader than a TIRF or CL&P's capital cost recovery mechanism (Attorney General Brief at 91). Therefore, the Attorney General recommends that the Department require the Company to re-engage with stakeholders to establish metrics, goals, and reporting requirements to ensure that the investments made in the CIRM deliver benefits to customers at a reasonable cost (Attorney General Brief at 91, citing Exh. AG-DO-CF-1, at 16-17; Attorney General Reply Brief at 52, n.20).

iii. O&M Offset

The Attorney General alleges that through the CIRM, National Grid will complete system replacements and enhancements, and as a result, the number and cost of failures will decline (Attorney General Brief at 91, citing Tr. 2, at 251-252; Attorney General Reply Brief at 52). For example, the Attorney General explains that the installation of reclosers on circuits would limit the area crews that the Company would need to patrol to locate outages (Attorney General Brief at 91, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). The Attorney General maintains that with a decline in outages, the Company also should experience lower O&M expenses (Attorney General Brief at 92, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). Therefore, the Attorney General recommends that the Company's CIRM include an O&M offset associated with the O&M savings resulting from additional capital investments (Attorney General Brief at 91-92, citing Exhs. AG-DO-CF-1, at 18; AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 50, 52, 53).

iv. Rate of Return

The Attorney General argues that if the Department decides to allow the CIRM as proposed by the Company, the Department should adjust downward the rate of return that the Company is allowed in the CIRM (Attorney General Brief at 94; Attorney General Reply Brief at 49, citing D.P.U. 07-50-A, at 71; Bay State Gas Company, D.T.E. 05-27, at 302 (2005); D.T.E. 02-24/02-25, at 229; D.T.E. 03-40, at 363; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977)). The Attorney General argues that a lower rate of return is reflective of the Company's reduction in risk associated with the recovery of most, if not all, of its capital investments in between base rate proceedings, with little regulatory lag (Attorney General Brief at 94, citing Exh. AG-DO-CF-1, at 20).

2. PowerOptions

PowerOptions argues that the Department must take a close look at proposed tracking mechanisms, such as the proposed CIRM, and decide whether they are warranted and in the best interest of ratepayers (PowerOptions Reply Brief at 9, citing D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52.) According to PowerOptions, while the tracking mechanisms benefit utility companies in terms of timely cost recovery, they are administratively onerous with annual filings requiring review by all interested parties, require numerous reconciliations and true-ups, and often result in additional charges to customers beyond base rates (PowerOptions Reply Brief at 9-10). Further, PowerOptions notes that the Department has found that where a company failed to demonstrate there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was

neither warranted nor in the best interests of ratepayers (PowerOptions Reply Brief at 10, citing D.P.U. 15-80/D.P.U. 15-81 at 54; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50-52).

Based on these considerations, PowerOptions argues that the Department must take a close look at whether extraordinary circumstances prevent National Grid from acquiring the capital necessary to make required investments in its infrastructure (PowerOptions Reply Brief at 10). PowerOptions contends that if the Department allows the CIRM, then it must decide whether an investment cap increase to $285 million is warranted and, if so, the Department needs to determine the process to ensure that there is appropriate oversight over these investments and proper review of the Company's three-year capital investment plan (PowerOptions Reply Brief at 10-11).

3. Company

a. Introduction

National Grid submits that its capital investments are increasing: (1) to maintain a resilient, modern electric grid substantially improved through technology; and (2) to meet customers' expectations for reliable service and information (Company Brief at 165). According to the Company, two modifications will improve the CIRM's operation (Company Brief at 166). First, National Grid proposes to increase the current investment cap of $170 million to $285 million, representative of the Company's actual plant additions during the test year (Company Brief at 166). Second, the Company proposes to include property tax expense in the computation of the revenue requirement because it is the "normal course for capital investment recovery mechanisms approved by the Department in other contexts" (Company Brief at 166).

The Company disagrees with the Attorney General's recommendation to eliminate the CIRM, and it rejects the Attorney General's alternative recommended modifications. The Company's positions regarding these issues are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Company argues that discontinuing the CIRM is implausible, especially considering the Commonwealth's energy efficiency programs, DG resources, and demand response programs that have been put in place since 2008 (Company Brief at 168). According to National Grid, the Department has recognized the direct impact on the Company's business when average consumption declines as a result of these conservation initiatives, namely the Company's inability to retain incremental sales revenue to support capital investment on a year-to-year basis (Company Brief at 168-169). National Grid acknowledges that revenue decoupling reimburses the Company for lost sales revenue due to reductions in consumption since setting its ATR (Company Brief at 165-166). However, the Company maintains that revenue decoupling also negates growth in sales that would have supported increases in the Company's cost of service between base rate proceedings (Company Brief at 165-166).[28] Thus, National Grid disagrees with the Attorney General's assertion that, through decoupling, the Company already is reimbursed and made whole for sales losses due to energy efficiency (Company Reply Brief at 69, citing Attorney General Reply Brief at 48).

Instead, National Grid contends that revenue decoupling does not return the value of sales volumes to the Company that is over and above the test year and were historically available to fund capital expenditures between base rate proceedings (Company Reply Brief at 70).

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[28] National Grid attributes increases in the cost of service largely to capital investment since its last base rate proceeding (Company Brief at 165-166).

According to National Grid, the Attorney General has failed to discredit evidence provided by the Company that the CIRM is necessary as a result of the Department's efforts to promote energy efficiency, demand resources, renewable energy, and DG (Company Reply Brief at 69, citing Exh. DPU-6-14). Thus, National Grid argues that if its revenues are decoupled from sales, the Company must retain its CIRM with the proposed modifications (Company Brief at 169-170).

Further, National Grid claims that its declining sales forecast demonstrates the success of the Department's efforts to achieve the objectives in D.P.U. 07-50-A (Company Brief at 170). According to the Company, without the downward sales pressure from DG and energy efficiency, the Company would have realized sales growth to offset its plant additions (Company Brief at 170, 171, citing Exh. DPU-6-14, Att.; Company Reply Brief at 69). According to the Company, the Attorney General did not rebut, evaluate, critique, or challenge: (1) the Company's sales forecast; or (2) that the Company's energy efficiency savings as a percent of total kilowatt hour ("kWh") delivery have doubled since 2010 (Company Reply Brief at 69; Company Brief at 168, citing Exh. NG-MLR-1, at 13).

Moreover, National Grid disputes the Attorney General's argument that the Company receives compensation and incentives for its energy efficiency programs (Company Reply Brief at 70). National Grid maintains that energy efficiency program costs are passed through to customers and any incentives that the Company receives are not sufficient to fund the Company's plant additions (Company Reply Brief at 70). For all these reasons, the Company asserts that the Attorney General did not provide creditable evidence in support of her position to discontinue the Company's CIRM (Company Reply Brief at 70).

c. Investment Cap

In response to the Attorney General, the Company argues that the current $170 million investment cap is insufficient for recovery of annual capital expenditures (Company Brief at 173). According to the Company, it has exceeded the $170 million cap by a total of $178 million since the CIRM's implementation (Company Brief at 173). Additionally, the Company argues that its plant additions and cost of removal in the test year alone exceeded the $170 million cap by more than $100 million (Company Brief at 173). Therefore, the Company asserts that the Attorney General's recommendation to set the investment cap at either $170 million or $183 million is not supported by record evidence (Company Reply Brief at 73).

In support of the proposed $285 million investment cap, the Company argues that it is under pressure to meet expanding service requirements and increased investment in distribution infrastructure (Company Brief at 166, citing Exh. NG-RRP-1, at 60). The Company maintains that it cannot meet the growing demand for capital investment without the CIRM, and that it will need to spend up to the $285 million investment cap to continue to meet its capital investment goals over the next three years (Company Brief at 167, citing Exh. NG-RRP-1, at 60; Company Reply Brief at 72, citing Exh. NG-JHP-1, at 29). The Company notes that it invested approximately $1.3 billion in its system between the end of 2008 and June 30, 2015 (Company Brief at 166, citing Exh. NG-RRP-1, at 60). Further, National Grid points out that it incurred $260 million in plant in service and $25 million in cost of removal in the test year (Company Brief at 166-167, citing Exh. DPU-32-22). Therefore, the Company asserts that a $285 million investment cap, based on actual capital expenditures in the test year, is more representative of the

Company's actual and projected investments (Company Brief at 174, citing Exh. NG-JHP-1, at 29).

National Grid also argues that increasing the investment cap to $285 million is in the best interest of ratepayers because it will contribute to maintaining service at current levels and assist the Company in complying with the Department's service-reliability metrics (Company Brief at 176, citing Exh. AG-7-5; Company Reply Brief at 73). National Grid claims that an investment cap based on a historical three-year or five-year average will not achieve the intended capital investment cost recovery and will render the CIRM moot (Company Brief at 174). In the alternative, the Company suggests that the Department approve a rolling three-year average investment cap, up to $285 million (Company Brief at 174, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277; Company Reply Brief at 73, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277).

d. Property Taxes

National Grid notes that the Attorney General did not challenge the Company's proposal to include property taxes in the CIRM (Company Reply Brief at 73). In support of the property tax modification, the Company explains that the current CIRM does not allow for recovery of property tax associated with annual capital additions made after the test year, which National Grid claims contradicts the Department's standard practice (Company Brief at 167, citing Exh. NG-RRP-1, at 62). The Company maintains that every other capital recovery mechanism approved by the Department includes property tax recovery, except for the recent mechanism approved for Fitchburg Gas and Electric Light Company (Company Brief at 162, 167, citing D.P.U. 15-80/D.P.U. 15-81, at 54; Tr. 1, at 95-96; Boston Edison

Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-82-A, at 53, 61 (2010)). The Company purports that incremental capital investment causes incremental increases in property tax (Company Brief at 167, citing Exh. DPU-10-2). Thus, National Grid argues that property taxes are directly attributable to the Company's capital additions and an unavoidable element of the CIRM revenue requirement (Company Brief at 167, citing Exh. NG-RRP-1, at 62). Additionally, the Company adds that the Department did not perform an investigation that would provide a foundation to exclude property tax from the CIRM (Company Brief at 167).

Moreover, National Grid claims that it did not originally propose to include property taxes in its CapEx proposal in D.P.U. 09-39 because the mechanism was one of four proposed rate recovery mechanisms: (1) the approved RDM; (2) the approved CapEx mechanism; (3) a proposed CapEx mechanism to recover projected capital investments; and (4) a proposed adjustment mechanism for net inflation (Company Brief at 161-162, citing D.P.U. 09-39, at 10). National Grid claims that it did not propose to recover property taxes in the approved CapEx mechanism because its proposed net inflation adjustment mechanism would have adjusted its total operating expense, including property taxes (Company Brief at 162, citing D.P.U. 09-39, Exh. NG-HSG-RR-8, at 2). The Company asserts that the Department did not "correct for this purposeful exclusion when it approved capital-cost recovery, while denying the net inflation adjustment" (Company Brief at 162). National Grid describes this result as an "inadvertent exclusion" and a "mistake" by the Department in D.P.U. 09-39 (Company Brief at 162). Therefore, National Grid concludes that there is no basis to exclude property taxes in the

calculation of the CIRM revenue requirement in the instant proceeding (Company Brief at 167; Company Reply Brief at 73).

e. Response to Attorney General's Recommended Modifications

The Attorney General recommends several modifications to the CIRM that National Grid claims lack justification, are unsubstantiated, and are contrary to the purposes of the CIRM (Company Brief at 176; Company Brief at 171-172, citing Attorney General Brief at 88; Company Reply Brief at 70). The Company argues that the Attorney General failed to provide persuasive testimonial evidence to support her recommended modifications to the proposed CIRM (Company Reply Brief at 71-72, citing Tr. 15, at 1602-1605, 1607-1608, 1613, 1617-1618, 1622-1628, 1630-1632). Further, National Grid contends that the Attorney General did not provide analytical support for any of her proposed modifications (Company Reply Brief at 71).

i. Scope

National Grid claims that the Attorney General's recommendation to narrow the scope of cost recovery in the Company's proposed CIRM, based on the design of capital cost recovery mechanisms in other jurisdictions, is unsubstantiated (Company Brief at 172, citing Attorney General Brief at 89; Tr. 15, at 1600-1609). In particular, the Company argues that the Attorney General's evidence of CL&P's storm hardening cost recovery mechanism is actually tied to a capital budget recovered though CL&P's base rates on a future test year basis (Company Brief at 172, citing RR-NG-2, Att. at 1, 8). Therefore, National Grid asserts that capital cost recovery is more favorable to electric distribution utilities in Connecticut than Massachusetts, a fact that the Company claims the Attorney General failed to recognize (Company Brief at 172-173).

ii. Benefits

The Company rejects the Attorney General's recommendation that the Department should include metrics to improve the accountability of customer benefits from the Company's capital spending in the CIRM (Company Brief at 176). The Company maintains that the Attorney General did not explain how the Department's existing service-quality metrics are deficient or suggest an alternative mechanism to include in the CIRM (Company Brief at 176).

iii. O&M Offset

National Grid contends that the Attorney General did not support her position to include an O&M offset in the CIRM (Company Brief at 176; Company Reply Brief at 73). The Company maintains that the O&M offset in the gas system enhancement plan cost recovery mechanism represents the elimination of a discrete O&M expense caused by gas leaks that no longer need repairs because the leaky pipe was replaced (Attorney General Brief at 176). According to the Company, there are no similarities in O&M savings between the CIRM and the gas system enhancement plan (Company Brief at 176; Company Reply Brief at 73).

iv. Rate of Return

Finally, the Company claims that the Attorney General did not rebut the Company's evidence showing that a deduction to the cost of capital is not warranted or appropriate (Company Brief at 176). Therefore, National Grid asserts that the Attorney General's modification to the rate of return on invested capital should be denied (Company Brief at 173, 176).

D. Analysis and Findings

1. Introduction

In D.P.U. 07-50-A at 48, the Department recognized that full revenue decoupling for electric companies would, all other things being equal, remove the opportunity for companies to retain additional revenues from sales growth between base rate proceedings -- revenues that companies could have used to pay for increased O&M costs, costs related to system reliability, and capital expansion projects. See D.P.U. 11-01/D.P.U. 11-02, at 73-74, 107; D.P.U. 10-70, at 47. The Department also recognized that changes in a distribution company's costs could arise from inflationary pressures on the prices of the goods and services it uses. D.P.U. 07-50-A at 49; see also D.P.U. 10-70, at 53. Accordingly, the Department stated that, along with revenue decoupling, it would consider company-specific proposals that adjust target revenues to account for capital spending and inflation but that a company would bear the burden of demonstrating the reasonableness of its proposal. D.P.U. 07-50-A at 50; see also D.P.U. 11-01/D.P.U. 11-02, at 107-108; D.P.U. 10-70, at 47.

In prior cases, when deciding whether to adopt a new capital cost recovery mechanism, the Department closely examined whether the mechanism was warranted and whether it was in the best interest of ratepayers. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52; D.P.U. 09-39, at 80-84.[29] The Department has allowed capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover

[29] National Grid was the first electric distribution company to receive approval for a CapEx mechanism following revenue decoupling. D.P.U. 09-39, at 80-84. Subsequently, the Department approved a CapEx mechanism for Fitchburg Gas and Electric Light Company. D.P.U. 15-80/D.P.U. 15-81, at 50. The Department also previously rejected a CapEx mechanism for Western Massachusetts Electric Company. D.P.U. 10-70, at 52.

incremental costs associated with capital expenditure programs between base rate proceedings. D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve a capital cost recovery mechanism as an element of decoupling. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; see also D.P.U. 07-50-A at 50. The Department has found that, where a company failed to demonstrate that there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers. D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50, 52.

2. Continuation of the CapEx/CIRM

National Grid acknowledges that the CapEx mechanism approved by the Department in D.P.U. 09-39 has not provided the Company with the level of benefits expected when originally proposed (Exh. NG-RRP-1, at 60-62). Thus, the Company proposes to increase the investment cap in its CIRM from $170 million to $285 million and apply a one-percent rate cap to the change in annual revenue requirement (Exhs. NG-RRP-1, at 61-62; DPU-32-22). Additionally, National Grid argues that the current CapEx mechanism does not provide for recovery of property taxes, a direct component of capital investment (Exhs. NG-RRP-1, at 62; DPU-10-2). Accordingly, the Company has proposed a modified CIRM that includes an investment cap of $285 million and for recovery of property taxes based on the ratio of test year property taxes to rate base (Exh. NG-RRP-1, at 61-62).

The Company must meet its service requirements and investment in distribution infrastructure, which has steadily increased since its last rate case (Exhs. NG-RRP-1, at 60; NG-MLR-1, at 6; DPU-18-5). See Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57 (2009) (a monopoly service provider has a public service obligation to provide reliable service at the lowest cost to customers); Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 6-7 (1986); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). National Grid invested approximately $1.3 billion in its electric distribution system from 2009 through June 30, 2015, and its actual expenditures on capital investment have exceeded the $170 million annual investment cap by an aggregate $178 million over the same period (Exhs. NG-RRP-1, at 60-61; AG-7-5, Att.; AG-16-2, Att.). The Company expects that its workload will increase significantly to provide safe and reliable service and it forecasts capital expenditures to increase from $302 million in 2015 to $311 million in 2017 (Exhs. DPU-10-6; DPU-18-5; AG-7-5). Moreover, the Company's test year plant additions were more than twice the level of the Company's depreciation expense of $127 million (Exhs. NG-RRP-1, at 60; NG-RRP-2, at 5 (Rev. 3)). Accordingly, National Grid would be unable to fully fund its test year level of capital expenditures, much less fully fund its projected increases in capital expenditures, through its base rate depreciation expense.[30]

National Grid also is experiencing an unprecedented level of DG and energy efficiency installations on its system, which cause diminishing sales revenues and increasing workload and expenses to administer the interconnection process for these installations (Exhs. NG-MLR-1,

[30] Depreciation expense is a non-cash expense associated with the use of an asset. Utilities often use depreciation expense as a funding source for capital expenditures.

at 13, 19; DPU-6-21). The Company ranks fifth in the United States in solar interconnections, at 405.3 megawatts ("MW") of interconnected DG solar over the period 2009-2015 (Exh. NG-MLR-1, at 19-20). Without the effect of increasing DG and energy efficiency, the Company's sales forecast derived solely on the basis of economic data would show positive sales growth over a five-year planning period (Exh. DPU-6-14, at 3). Thus, the Company estimates that DG and energy efficiency are reducing sales by approximately 2.3 percent cumulatively per year based on historical installations, and could increase to sales reductions of 6.5 percent cumulatively per year over a five-year planning period, based on additional installations (Exhs. DPU-6-14, at 4; DPU-6-14, Att. at 21).

Based on these considerations, the Department finds that the Company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate cases. Accordingly, we will allow the operation of the Company's CIRM. D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. In this regard, we further find that the CIRM shall operate independent of the Company's revenue decoupling provision. Although the Department stated that we would consider proposals to adjust ATR in an RDM, separating the mechanisms produces the same result for the Company. The RDM reconciliation will annually true-up the over- or under-recovery of base distribution rates, while the CIRM will annually true-up the over- or under-recovery of the Company's allowed annual capital expenditure. See D.P.U. 07-50-A at 50. Separating the CIRM component from the RDM allows for administrative efficiency and the application of separate rate caps.

National Grid proposes an annual rate cap on the CIRM revenue requirement at one percent of total revenues (Exh. NG-PP-23, at 178, (proposed M.D.P.U. No. 1277, at sheet 3)). The Department finds that a one-percent rate cap adequately protects ratepayers from excessive annual increases to distribution rates. See D.P.U. 10-55, at 133. To the extent that the application of the one-percent rate cap results in a CIRM revenue requirement that is less than that calculated, National Grid shall defer the difference and include in the CIRM reconciliation for recovery in the subsequent year. Carrying charges shall be calculated on the average deferred balance using the customer deposit rate (Exh. NG-PP-23, at 178 (proposed M.D.P.U. No. 1277, at sheet 3)). Additionally, the one-percent rate cap is consistent with other capital tracking mechanisms approved for utilities in Massachusetts. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 53-54; D.P.U. 10-55, at 133.

The Department now allows the Company's CIRM to operate separately from the Company's revenue decoupling provision. Below, the Department addresses the Company's proposed modification to increase the investment cap to $285 million and to include property taxes in the annual revenue requirement. We also address the Attorney General's recommended modifications to the CIRM.

3. Investment Cap

The Company proposes to increase its investment cap to $285 million, based on its test year plant additions and cost of removal (Exhs. NG-RRP-1, at 61; DPU-10-6, Att.; RR-DPU-9; RR-DPU-14). The Attorney General asserts that the investment cap should remain at $170 million, or in the alternative, be set at $183 million, representing the five-year average of

plant additions, excluding cost of removal (Exh. AG-DO-CF-1, at 8; Attorney General Brief at 93, citing RR-DPU-14).

Capital cost recovery mechanisms reduce and potentially eliminate the important incentive that regulatory lag provides to companies to maintain an appropriate balance between investing in capital improvements and incurring O&M expenses. D.P.U. 09-39, at 81. To reach a balance between: (1) providing the Company with sufficient capital funding to ensure the safety and reliability of the electric service that it provides to its ratepayers; and (2) protecting its ratepayers against the incentive the Company has to overinvest in capital infrastructure in order provide earnings to its shareholders, the Department has directed companies to implement investment caps. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 81-82.

After review of the record and the arguments of the parties, the Department finds it appropriate to implement an investment cap based on the historical three-year average of capital spending, or $249 million (Exh. DPU-10-6 & Att.).[31] We conclude that using this three-year average of capital spending as the limit on CIRM revenue requirement is appropriate because it is representative of National Grid's current capital investment needs and, as such, strikes the appropriate balance between: (1) providing the Company with sufficient funds to ensure safe and reliable electric service; and (2) protecting ratepayers from over-investment in capital infrastructure. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82.[32]

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[31] The $249 million historical three-year average of capital spending (including cost of removal) is calculated based on capital spending of approximately $176 million in 2013, $270 million in 2014, and $302 million in 2015 (Exh. DPU-10-6 & Att.).

[32] The Department expects the Company's first CIRM filing to reflect six months of capital investments (i.e., July 1, 2015-December 31, 2015). Therefore, the Department directs the Company to prorate the annual $249 million investment cap (i.e., $124.5 million) to

The Department makes no determination regarding the optimal level of investment the Company should make in its distribution infrastructure in order to provide safe and reliable electric service to its ratepayers in satisfaction of its public service obligation.[33] The Company's maintenance and replacement activities may lead the Company to identify capital investments that exceed the level of the three-year average

4. Property Taxes

In D.P.U. 15-80/D.P.U. 15-81, the Department excluded property taxes from Fitchburg Gas and Electric Light Company's capital cost recovery mechanism on the basis that capital cost recovery mechanisms are not intended to provide a company with dollar-for-dollar recovery of capital investments between rate cases, and are intended to provide rate relief in between base distribution rate cases to fund capital investments that otherwise were available to be funded through sales growth prior to decoupling. D.P.U. 15-80/D.P.U. 15-81, at 54. Based on the record in this proceeding, however, it is apparent that the exclusion of property taxes does not provide the appropriate rate relief between base rate proceedings to fund capital investments that were available to be funded through sales growth prior to revenue decoupling (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Further, based on the record in this proceeding, the Department is persuaded that property taxes are directly attributable to the Company's capital additions (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Incremental increases in property taxes are inextricably linked to incremental

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account for only six months of capital investment in the first annual CIRM filing following this Order.

[33] In this regard, the Department relies on the Company to make sound management, business, and engineering decisions.

capital investment funded through the CIRM. Moreover, under the Company's current CapEx mechanism, the Company's return on rate base was 1.18 percent (compared to its authorized return of 8.14 percent) (Exhs. NG-MLR-1, at 4; AG-16-1). See also Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39-A at 38 (2010). The Department concludes property taxes represent a significant cost related to capital investments, and excluding them from the CIRM may contribute to earnings erosion and may negatively affect capital investment.

We recognize that the Department's decision today shifts from the policy direction previously stated in D.P.U. 15-80/D.P.U. 15-81. However, we find that the change here is necessary in order to provide the Company with a necessary and appropriate level of rate relief. Moreover, the Department's goal in the inclusion of property taxes in the CIRM is to mitigate the need for base rate relief prior to the five-year interval prescribed by § 94, ultimately to the benefit of ratepayers. Further, we note that permitting the Company to recover property taxes associated with CIRM investments will not result in dollar-for-dollar recovery of all property taxes. The Company proposes to include property taxes in its CIRM using a ratio of total annual property taxes paid in the test year to total taxable net plant in service in the test year (Exhs. NG-PP-23, at 176 (proposed M.D.P.U. No. 1277, at sheet 1); DPU-18-8, Att.). Based on the Company's original cost of service data, the property tax rate for the CIRM calculation is 2.63 percent (Exhs. NG-RRP-2, at 28, 30 (Rev. 1); DPU-18-8). The Company multiplies the 2.63 percent property tax rate by net plant to determine the property tax expense recoverable through the CIRM (Exh. DPU-18-8). Because National Grid is not permitted to recover the revenue requirement associated with the investment vintage year, the full property tax expense

on CIRM investments are not fully realized in the CIRM until the third year's revenue requirement calculation (Exh. DPU-18-8). Therefore, property taxes recoverable in the CIRM are not actual incurred expenses on the new CIRM investment in the vintage year.[34]

Further, based on a CIRM with an investment cap of $285 million (i.e., the Company's proposal), National Grid would not collect property taxes for the first year of the investment, and in the second and third years of the CIRM, it would collect approximately $3 million and $6 million, respectively, associated with only the first year of capital investment (Exh. DPU-18-8, Att. at 1). In addition, to the extent that the Company's annual capital investment exceeds the investment cap, the Company will not recover property taxes associated with these investments until its next base rate case. Therefore, the Company's CIRM retains a measure of regulatory lag. For all of the foregoing reasons, the Department allows the Company's proposal to include property taxes in the calculation of the CIRM revenue requirement.

5. Attorney General's Modifications

The Department declines to adopt the Attorney General's recommendations to limit the scope of the CIRM and to implement an O&M offset. The Attorney General did not provide persuasive evidence on how or what to limit the scope of the CIRM or provide sufficient quantification of any O&M offset (see Exhs. AG-DO-CF-1, at 11-12, 18-19;

[34] Moreover, the property tax expense associated with CIRM investments is not based on actual property tax bills. Thus, annual incremental property taxes associated with CIRM investments are not recovered on a dollar-for-dollar basis.

AG-DO-CF-Rebuttal-1, at 7-9).[35] Finally, we find that the Attorney General did not substantiate with appropriate analysis her recommendation for a lower rate of return applicable to the CIRM. Therefore, we decline to adopt her recommendation. The Department discusses the Company's overall rate of return, and whether the approved CIRM reduces risk, in Section XII.E below.

Regarding benefits, the Attorney General recommends that the Department require the Company to re-engage with stakeholders to establish metrics, goals, and reporting requirements to ensure that the investments made in the CIRM deliver benefits to customers at a reasonable cost (Attorney General Brief at 91, citing Exh. AG-DO-CF-1, at 16-17; Attorney General Reply Brief at 52, n.20). See D.P.U. 09-39, at 84. After the Department's directive in D.P.U. 09-39, the Company coordinated three meetings to develop capital spending metrics for future years (Exh. DPU-18-6). National Grid was unable to reach an agreement on the purpose or iteration of the metrics as of April 4, 2012 (Exh. DPU-18-6). The Company stated that because the annual CapEx mechanism proceedings were suspended, it did not re-engage stakeholders to reach an agreement (Exh. DPU-18-6).

With this Order, the previous CapEx mechanism proceedings will be resolved (see Section VII.B.6). However, the Company will continue to make future CIRM filings. Thus, the Department directs the Company to continue to work toward the development of a capital plan that includes goals and metrics by which to measure and quantify its success. Accordingly, within 120 days of the date of this Order, National Grid shall provide the Department with a report detailing the Company's efforts to develop such goals and metrics. In conjunction with this report, the Company shall update and file the Proposed Capital Plan Metrics Capital Plan

[35] Despite making this recommendation, the Attorney General could not point to any such category or external factor to limit the scope of the CIRM (Exh. AG-DO-CF-1, at 11-12).

labeled as Exhibits AG-4-9-A and AG-4-9-B in docket D.P.U. 11-60. Upon review of the Company's filing, the Department will determine the appropriate next steps.

6. Conclusion

The Department allows the Company's proposal to operate the CIRM outside of the RDM. The Department also approves a modified investment cap of $249 million, a one-percent rate cap, and the Company's proposal to include property taxes in the CIRM revenue requirement. In compliance with this Order, the Department directs the Company to modify its CIRM tariff according to the foregoing directives. Further, the Company shall make all future CIRM filings in compliance with the directives set forth in Section VII.B.5.b.viii below.

VI. STORM COST RECOVERY MECHANISM

A. Introduction

1. Background of the Storm Fund

Pursuant to a rate plan settlement in D.T.E. 99-47 ("D.T.E. 99-47 Settlement"), the Department approved the collection by the Company of $4.3 million annually in base rates for contribution to a storm fund. In accordance with the terms of the D.T.E. 99-47 Settlement, the Company was permitted to access the storm fund when the cost of responding to an individual storm exceeded $1.25 million. D.T.E. 99-47 Settlement, Att. 5. The D.T.E. 99-47 Settlement also established a cap on the storm fund balance of $20 million, adjusted for inflation, applicable to the storm fund. D.T.E. 99-47 Settlement at 15. In the event the cap was exceeded (either positive or negative), the excess or deficiency was to be recovered or refunded over a five-year period. D.T.E. 99-47 Settlement, at 15. Finally, the D.T.E. 99-47 Settlement provided for

interest to be applied on the storm fund balance (or deficit) at the customer deposit rate. D.T.E. 99-47 Settlement, Att. 5.

In the Company's last base rate case, D.P.U. 09-39, the Department approved the Company's proposal to continue the storm fund, but also determined that several modifications to the storm fund were necessary. D.P.U. 09-39, at 205-213. The Department maintained the annual storm fund collection of $4.3 million in base rates. D.P.U. 09-39, at 207. However, the Department rejected the Company's request to recover through the storm fund all expenses associated with an individual storm that exceeds $1.25 million in restoration costs, and instead permitted the Company to recover only the costs in excess of $1.25 million. D.P.U. 09-39, at 207. Further, the Department rejected the Company's proposal to carry a credit balance in the storm fund at the customer deposit rate and a deficit balance at the weighted average cost of capital ("WACC"). D.P.U. 09-39, at 207. Instead, the Department found it appropriate for the storm fund balance (whether credit or deficit) to accrue interest at the Company's WACC determined in that proceeding. D.P.U. 09-39, at 208.

In addition, National Grid proposed to remove the cap on the fund balance on the credit side and, if the storm fund had a deficit balance in excess of $8.6 million, include on an annual basis the amount in excess of $8.6 million as a distribution adjustment with carrying costs at the Company's WACC. D.P.U. 09-39, at 208. The Department rejected this proposal and instead continued the symmetrical cap of $20 million. D.P.U. 09-39, at 208. The Department found that in the event the cap was exceeded as the result of a surplus, then the amount over the cap collected from ratepayers in that year would be returned in the following year. D.P.U. 09-39,

at 208.[36] In the event the cap was exceeded as a result of a deficiency, the Company would have the option to propose to the Department an alternative method for recovery of incremental costs that exceed the cap. D.P.U. 09-39, at 208-209.

Finally, the Department found that in order to recover any costs from the storm fund, National Grid must obtain approval from the Department by demonstrating that the costs the Company seeks to recover from the fund are storm related, incremental, exceed the $1.25 million threshold, and were prudently incurred. D.P.U. 09-39, at 209. National Grid was directed to submit as part of its filing a report that outlines the total number and costs of all storms that occurred in the past year. D.P.U. 09-39, at 209.

2. Storm Cost Recovery Filings

Pursuant to the directives set forth in D.P.U. 09-39, the Company petitioned the Department in March 2013 for recovery of the $212 million storm fund deficit balance related to 14 storms that took place between February 2010 and February 2013. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-59, at 1-2, 4 & n.2 (2013). The Department approved a Storm Fund Replenishment Adjustment Factor ("SFRF")[37] designed to replenish the storm fund by $40 million annually for three years, beginning on May 4, 2013.

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[36] The Department found that consistent with the treatment of the recovery and reconciliation of pension costs and gas costs (220 C.M.R. § 6.08(2) for gas costs), the amount of storm costs to be reconciled would be returned through a kWh delivery surcharge with carrying costs on the reconciliation of forecast to actual recovery at the prime rate. D.P.U. 09-39, at 208, citing NSTAR Pension, D.T.E. 03-47-A at 46 (2003).

[37] Also referred to in other cases as the Storm Fund Replenishment Adjustment.

D.P.U. 13-59, at 14.[38] The Department also directed National Grid to file for a prudency review, no later than May 31, 2013, to include all supporting invoices for storm events that occurred between 2010-2011, and to file no later than December 31, 2013, for storm events occurring through February 2013. D.P.U. 13-59, at 2, 15.

Pursuant to the Department's directives in D.P.U. 13-59, the Company filed for recovery of the deficit balance in the storm fund associated with the incremental costs for eight storms that occurred between February 2010 and October 2011, and for eight storms that occurred between January 2012 and March 2013. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-85, at 1 (2016).[39] In D.P.U. 13-85, the Department approved the recovery of costs associated with these storms. D.P.U. 13-85, at 101, 106.[40] The Department also extended the SFRF through June 2018, because it will eliminate the storm fund deficiency associated with these 16 storms and will avoid approximately $7.6 million in carrying changes, to the benefit of ratepayers. D.P.U. 13-85, at 105.

According to the Company, between November 2013 and February 2015, there have been nine additional storms that qualify for recovery under the storm fund (Exh. NG-RRP-1,

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38 In a separate proceeding, the Department approved the transfer to the SFRF of recovery of outstanding costs related to a 2008 ice storm. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-85, at 7 (2014).

39 The 16 storms for which the Company sought cost recovery included the 14 aforementioned storms and two additional storms that occurred in 2013.

40 The final amount of approved costs is subject to confirmation by the Department following the Company's compliance filing in that proceeding. D.P.U. 13-85, at 101, 106.

at 67-68).[41] Thus, since 2010, there have been 25 storms that qualified for recovery through the storm fund (Exh. NG-RRP-1, at 68, 75). The net amount of incremental O&M expense eligible for reimbursement from the storm fund for these 25 events in total is $243 million (Exh. NG-RRP-2, at 26 (Rev. 3)).

B. Company Proposal

The Company proposes to continue its storm fund and to maintain the current $1.25 million cost-per-storm threshold for accessing the storm fund (Exhs. NG-RRP-1, at 68-69; DPU-21-17). However, the Company proposes four modifications to the current storm fund. First, the Company proposes to extend the SFRF to August 2019 in order to continue the more rapid replenishment of the existing storm fund to account for the nine additional qualifying storm event costs that took place after the Company's filing in D.P.U. 13-85, and to minimize the carrying costs associated with those storms (projected to be $32 million at the start of the rate year) (Exhs.NG-RRP-1, at 68-69, 78, 82; NG-RRP-6c, at 2). In this regard, the Company also proposes to transfer the deficit balance to be collected through the SFRF to a separate regulatory asset, and reset the storm fund balance to zero (Exh. NG-RRP-1, at 78). Further, the Company proposes that any residual balance (either positive or negative) remaining in the regulatory asset at the end of the extended recovery period (i.e., August 2019) then would be transferred to the Company's storm fund (Exh. NG-RRP-1, at 78-79).

Second, the Company proposes to increase from $4.3 million to $14 million, the amount collected annually through base rates and designated to the storm fund (Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 4, 26 (Rev. 3)). The Company states that based on its history of storm

[41] The Company has not yet filed for a prudency review of these nine storms (Exh. NG-RRP-1, at 82).

events since its last rate case this proposal provides a more appropriate amount for the base-rate contribution, balances customer rate impact, and normalizes cost recovery for extraordinary storm events (Exh. NG-RRP-1, at 69, 86). In calculating the proposed base rate amount, the Company first eliminated from consideration $150 million in costs related to the three costliest storms that occurred between 2009 and June 30, 2015 (Exhs. NG-RRP-1, at 86; NG-RRP-2, at 26).[42] The Company then took an average of the remaining $93 million in storms costs ($243 million in net incremental storm costs minus $150 million) over the number of months between the end of the test year in D.P.U. 09-39 and the end of the test year in the instant proceeding, or 78 months, to arrive at an annualized amount of $14.0 million (Exhs. NG-RRP-1, at 86; NG-RRP-2, at 26 (Rev. 3)).

Third, the Company proposes to increase the storm fund's symmetrical cap on the balance in the fund from $20 million to $30 million to coincide with its proposed increase in the annual base rate contribution for storm costs (Exhs. NG-RRP-1, at 88-89). The Company states that it is necessary to raise the cap to $30 million in order to minimize the potential for frequent rate changes, either positive or negative (Exh. NG-RRP-1, at 89).

Fourth, the Company proposes to modify the current method by which carrying costs are applied to storm costs that are recovered through the storm fund, so that interest will accrue on incremental storm costs when such costs are filed for recovery with the Department (as opposed to when these costs are incurred) (Exh. NG-RRP-1, at 87). In this regard, the Company proposes that interest will accrue on the combination of the storm fund reserve and the costs related to the

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42 These three storms were: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; and (3) Nor'easter Nemo in February 2013 (Exh. NG-RRP-1, at 86).

storms filed for storm fund cost recovery (Exh. NG-RRP-1, at 88). If the storm fund balance is in a surplus, then the Company proposes that interest will accrue at a carrying charge rate equivalent to the Company's pre-tax WACC, as determined by the Department (Exh. NG-RRP-1, at 87). Conversely, if the combined storm fund balance is in a deficit, then the amount in deficit (up to the $30 million cap) would accrue interest at the Company's customer deposit rate (Exh. NG-RRP-1, at 88). Further, any storm fund deficit in excess of the proposed $30 million storm cap would accrue interest at a carrying charge rate equivalent to the pre-tax WACC (Exh. NG-RRP-1, at 88).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that National Grid's storm fund should be eliminated because the Company failed to demonstrate that: (1) storm costs represent "extraordinary circumstances"; and (2) the storm fund is in the best interest of ratepayers (Attorney General Brief at 94-97, citing D.P.U. 13-90, at 14; Attorney General Reply Brief at 53, 57-58). Instead, the Attorney General asserts that the Company should recover storm costs through base distribution rates at a representative historical level (Attorney General Brief at 95). According to the Attorney General, if a storm results in extraordinary costs, National Grid could: (1) request from the Department deferral of these costs for consideration of recovery in its next base rate case; or (2) file for storm cost recovery through a base rate case proceeding, thereby allowing the storm costs to be weighed along with other factors affecting the Company's financial stability (Attorney General Brief at 95). On this last point, the Attorney General notes that annual rate cases should not be the norm if the storm fund is discontinued, and that the Company has a

fiduciary obligation to act in the best interest of ratepayers and provide safe, reliable, and least-cost service (Attorney General Reply Brief at 57-58, citing D.P.U. 10-70, at 229 n.123; Incentive Regulation, D.P.U. 94-158, at 3 (1995); Integrated Resource Planning, D.P.U. 94-164, at 51-52 (1995)).

Alternatively, the Attorney General argues that if the Department continues the Company's storm fund, three revisions should be made. First, she contends that the cost-per-storm threshold to access the storm fund should be increased from $1.25 million to $2.4 million (Attorney General Brief at 98; Attorney General Reply Brief at 56-57). According to the Attorney General, storm costs have increased over time and this proposed threshold more accurately reflects the increase in costs (Attorney General Brief at 98, citing Exh. DPU-AG-1-9; Attorney General Reply Brief at 55-56). She also contends that under the current threshold of $1.25 million, the Company accesses the storm fund on average 4.5 times per year (i.e., 25 storms over a five and one half year period) (Attorney General Brief at 98, citing Exh. DPU-AG-1-19; Attorney General Reply Brief at 56).[43] Thus, she claims that many storms considered by the Company to be "major" are actually more likely to be "routine" (Attorney General Brief at 98, citing Exh. AG-DO-CF-Rebuttal-1, at 3-4; Attorney General Reply Brief at 56). The Attorney General asserts that increasing the threshold to $2.4 million likely would reduce storm fund access to, on average, 2.7 times per year and ensure that only those events that clearly fall outside of normal risk built into rates would be eligible for storm fund recovery (Attorney General Brief at 98, citing Exh. AG-1-19; Attorney General Reply Brief at 56-57).

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[43] The Attorney General's five and one half year period appears to be 2010 to the end of the test year in this case (Exh. DPU-AG-1-19 & Att.)

Second, the Attorney General argues that the amount collected annually through base rates and designated to the storm fund should increase from $4.3 million to $4.8 million (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50; Attorney General Reply Brief at 53 n.21). In this regard, she contends that if the storm fund threshold had been $2.4 million rather than $1.25 million, and if the five costliest storms of the 25 storms at issue were excluded from consideration,[44] only 15 storms would have qualified for storm fund cost recovery (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29). According to the Attorney General, the annualized amount of the net incremental O&M expense associated with these 15 storms was $4,766,284, thereby justifying the recommended representative level of $4.8 million (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50).

Third, the Attorney General argues that the carrying charge applied to any unrecovered balance in the storm fund should be set at the customer deposit rate and not the WACC (Attorney General Brief at 98; Attorney General Reply Brief at 53).[45] According to the Attorney General, the application of the WACC to deferred storm fund-eligible costs has permitted the Company to recover $81 million in interest between 2010 and 2015 (Attorney General Brief at 98, citing Exhs. NG-RRP-6b, at 2; AG-DO-CF-1, at 27-28; Attorney General Reply Brief at 54). Further, the Attorney General contends that the application of the WACC to deferred storm

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44 These five storms are: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; (3) Nor'easter Nemo in February 2013; (4) Hurricane Sandy in October 2012; and (5) Blizzard Juno in January 2015 (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29).

45 The Company's current pre-tax WACC is 11.48 percent (Exh. NG-RRP-6a). The Company's customer deposit rate is 0.69 percent, which is equivalent to the average rate paid on two-year United States Treasury notes for the twelve months ended December 31, 2015, as stated in the Federal Reserve Statistical Release.

fund-eligible costs has led to considerable risk and cost inappropriately being transferred to ratepayers (Attorney General Brief at 98; Attorney General Reply Brief at 54). Thus, she asserts that to avoid this risk transfer, and because she argues that the deferral of storm costs is short-term, the Department should adopt the customer deposit rate as the appropriate carrying charge (Attorney General Brief at 98-99; Attorney General Reply Brief at 54-55).[46]

2. PowerOptions

PowerOptions argues that the Company's storm fund must be carefully examined and that preparing for storms, and properly repairing the distribution system after storms, are part of "doing business" in New England (PowerOptions Reply Brief at 11). Further, PowerOptions contends that if the Company's storm fund is continued, the Department should adopt the Attorney General's recommendations to raise the cost-per-storm threshold to access the storm fund from $1.25 million to $2.4 million (PowerOptions Reply Brief at 11). PowerOptions agrees with the Attorney General that increasing the threshold likely will reduce the number of storms that qualify for storm fund recovery and ensure that only those larger-scale storm events that clearly fall outside of normal risk built into rates would be eligible for such recovery (PowerOptions Reply Brief at 11).

3. Company

National Grid asserts that the storm fund should continue, and the Company rejects the various arguments raised by the Attorney General in support of terminating the fund (Company Brief at 183-189). In particular, the Company argues that the storm fund provides a necessary

[46] The Attorney General states that if the Department raises the cost-per-storm threshold to $2.4 million and if the customer deposit rate is used to accrue carrying charges on the deficit, the $20 million cap on the fund balance "will likely suffice" (Exh. AG-DO-CF-1, at 29).

means of cost recovery that appropriately correlates to the strict requirements imposed on electric companies for immediate and unqualified response to storms (Company Brief at 183-184). In this regard, the Company contends that there is no feasible manner by which the magnitude of storm costs now incurred simply could be deferred for later recovery in a future rate case, and that annual rate cases would be necessary to achieve a level of recovery that would satisfy the Company's rating agencies (Company Brief at 184, 187). National Grid asserts that such an outcome would be detrimental to ratepayers and the financial integrity of the Company (Company Brief at 184).

The Company proposes to maintain the $1.25 million threshold that currently applies to determine eligibility for storm fund recovery (Company Brief at 179). The Company rejects the Attorney General's recommendation to increase the cost-per-storm threshold to access the storm fund from $1.25 million to $2.4 million (Company Brief at 189). According to the Company, the Attorney General's recommended threshold is not based on any analysis whatsoever, but is simply a "mathematical computation to back into a recommendation concluding that only two storms a year should qualify" (Company Brief at 190-191). Conversely, the Company contends that the $1.25 million is set at a point that draws a distinct line between events that require a response using resources that are contemplated in base rates and those events that involve costs that are not included in base rates, which are largely related to the costs of external crew complements called into pre-stage for relatively larger impact events (Company Brief at 191). Further, the Company notes that between 2010 and 2015, there were 240 discrete storm events that caused the Company to incur incremental repair and restoration costs, but only 25 of these events (or approximately ten percent) qualified for storm fund

recovery (Company Brief at 190, 192, citing Exh. NG-RRP-1, at 66-68). Thus, the Company asserts that the $1.25 million threshold is appropriate (Company Brief at 192). However, the Company notes that in the event the Department does raise the threshold, a corresponding increase in base rates is necessary to fund storm costs for those storms that would not meet the threshold (Company Brief at 191-192; Company Reply Brief at 74).[47]

With respect to National Grid's proposal to increase the annual base rate contribution to the storm fund to $14.0 million, the Company argues that the current annual contribution of $4.3 million is not sufficient because the number of qualifying events is increasing due to prevailing weather patterns and the strict emergency response requirements placed on the Company by Massachusetts law and the Department's regulations (Company Brief at 179-180, citing Exh. DPU-32-10). Further, the Company argues that if the Department does not increase the current amount of $4.3 million collected annually through base rates and contributed to the storm fund, there will continue to be a relatively greater need to defer and delay storm-cost recovery (Company Reply Brief at 74).

Next, National Grid argues that its proposal with respect to carrying costs is designed to more equitably share with ratepayers the risk related to major storms (Company Brief at 180, citing Exh. NG-RRP-1, at 87-88). National Grid contends that it cannot defer hundreds of millions of dollars for multiple years, with another five years or more needed for recovery,

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[47] The Company maintains that large storm costs are not appropriate for the "ebb and flow" of base ratemaking treatment because: (1) it is not possible to reasonably identify a "representative" level of major storm events; and (2) as the threshold increases, there is an increase in the "win or loss" that occurs for the ratepayers and Company (Company Brief at 192). However, the Company argues that if the threshold is set at $2.4 million, as recommended by the Attorney General, the Department should increase base rates by $5.2 million (Company Reply Brief at 74, citing Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46).

without recovery of adequate carrying costs (Company Reply Brief at 74). Thus, the Company asserts that any changes to the storm fund that build in delay and deferral must be accompanied by adequate carrying costs (Company Reply Brief at 74).

Finally, the Company argues that its symmetrical cap proposal is designed to protect against substantial accumulation of fund balances creating an oversized surplus or potentially harmful deficit (Company Brief at 181, citing Exh. DPU-21-18). The Company contends that given recent qualifying storm events, an increase in the symmetrical cap on the fund balance from $20 million to $30 million is a necessary change to minimize the potential for frequent rate changes, to accommodate the greater level of annual customer contribution proposed in this case, and to provide for more stable rates for customers (Company Brief at 181, citing Exhs. NG-RRP-1, at 89; DPU-21-18). Thus, according to the Company, the proposed symmetrical cap and the base distribution rate contribution are intended to work in conjunction with one another to establish rate stability for customers (Company Brief at 181).

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to levelize storm restoration costs of major storms on ratepayers. D.P.U. 13-90, at 13, citing D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. However, the Department has recognized that recent experience, both with National Grid and other electric utilities, has demonstrated that the use of storm funds may shift the burden of cost recovery disproportionately to ratepayers without providing commensurate benefits. D.P.U. 13-90, at 13. As such, the Department has put all electric distribution companies on notice that if they seek continuation of a storm fund in their

next base distribution rate case, they must demonstrate why the continuation of a storm fund is in the best interest of ratepayers. D.P.U. 13-90, at 14-15.

2. Continuation of the Storm Fund

Since the Company's last rate case, the Department has devoted significant time and resources to the improvement of each electric utility's storm response. As a result, storm response requirements are now more formalized, more comprehensive, and more rigorous. See, e.g., G.L. c. 164, § 1J; 220 C.M.R. § 19.03 (setting forth standards for the acceptable performance for emergency preparation and restoration of service for electric and gas companies); Investigation by the Department of Public Utilities into the Storm Preparation and Response of Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-85-A/11-119-A at 153 (2012) (imposing penalties for Company's failure to restore service to its customers in a safe and reasonably prompt manner). In order to meet these requirements, electric distribution companies are expected to properly prepare for and implement storm response measures that restore power safely and expeditiously. These obligations require the Company to devote substantial resources to achieving the desired results. Further, as recent history indicates, the frequency and severity of major storm events has increased (see, e.g., Exh. DPU-32-4, Att. (25 major storms since 2009)). Not surprisingly, the costs of responding to those events to restore power for customers in an expeditious fashion have increased as well.

We acknowledge that National Grid's current storm fund mechanism has not provided the desired balance between cost recovery and rate stability. In particular, the overall number of major storms in the past six and a half years contributed to a large storm fund deficit that

expanded even further due to the accumulation of a significant amount in carrying charges. The number of these storms themselves could not have been anticipated when the storm fund mechanism was developed for the Company, although we have certainly seen a trending to more severe storms over the past several years than previously experienced. As a result, without a storm fund mechanism it is unlikely that during this time frame the Company could have absorbed these costs without filing a base rate case, or even multiple rate cases, which could have resulted in an increase in rates to ratepayers for other costs.

Therefore, we find that if properly structured, the Company's storm fund can provide for adequate recovery of storm costs from customers in a manner that is designed to create rate stability. On that basis we conclude that the storm fund shall continue, but with several important modifications, as discussed below.[48]

3. Modifications to the Storm Fund

a. Cost-Per-Storm Threshold

Currently, for any storm for which National Grid incurs more than $1.25 million in costs, the Company is permitted to access the storm fund for reimbursement of only that portion of the costs that exceed $1.25 million. D.P.U. 09-39, at 207. The Company's current threshold of $1.25 million per storm was first established in the D.T.E. 99-47 Settlement and was maintained following the Department's adjudication of the proposed modifications to the storm fund in D.P.U. 09-39. It stands to reason that per-storm restoration costs have increased since 2009. Thus, we find that it is appropriate to increase the cost-per-storm threshold to reflect the general

[48] Further, we note that pursuant to § 94, the Company must file its next base rate case within five years. At that time, the Department will have another opportunity to review the modified storm fund and determine whether it should continue even further.

increase in costs and to prevent the inclusion in the storm fund of future storm events of a more routine nature.

The Attorney General recommends that the cost-per-storm threshold should be increased to $2.4 million to better reflect the frequency of "truly" major storms (Attorney General Brief at 98, citing Exh. DPU-AG-1-19; Attorney General Reply Brief at 56-57). The Company did not propose an increase to the cost-per-storm threshold, but argues that any such increase must come with a corresponding increase to the amount collected through base rates to address smaller storms that do not qualify for storm fund recovery (Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46).[49]

The Department has considered the arguments and has reviewed the record concerning the cost-per-storm threshold (Exhs. NG-RRP-Rebuttal-1, at 9-10; NG-DEB-Rebuttal-1, at 3-7; AG-DO-CF-1, at 28; AG-DO-CF-Rebuttal-1, at 4-5; DPU-21-18; DPU-32-2; AG-6-1; DPU-AG-1-19 & Att.; Tr. 15, at 1633-1649, 1670-1676, 1680-1681; RR-DPU-46; RR-DPU-51). The Department finds that it is appropriate to increase the threshold to account for the effect of inflation on costs during this period. Absent an inflation adjustment to the current threshold to bring incremental O&M service restoration costs to present value terms, the cost of a storm in 2009 (in present value dollars) would be less than the cost of that same storm in 2015. Therefore, the Department finds that the threshold should be increased by inflation based on the gross domestic product price index ("GDP-PI") from the U.S. Bureau of Economic Analysis for the period between 2009 and June 30, 2015, which would increase the current $1.25 million

[49] The Company collects through base rates (1) an annual amount for contribution to the storm fund reserve, and (2) an annual amount to cover costs up to the cost-per-storm threshold and for smaller storm events that do not qualify for the storm fund.

threshold by approximately ten percent to approximately $1.5 million.[50] We find that this increased cost-per-storm threshold provides an appropriate balance between providing the Company with necessary access to the storm fund to recover costs associated with major storms and ensuring that the routine storms are not contributing to a storm fund deficit balance.

Further, we find that the increase in the cost-per-storm threshold applicable to the storm fund also necessitates changes in the amount the Company collects through base rates to (1) contribute to the storm fund, and (2) recover O&M costs up to the $1.5 million threshold for storms that qualify for the storm fund, as well as costs associated with smaller storm events that no longer qualify for storm fund recovery. These issues are discussed in the next section.

b. Amounts Collected through Base Rates

i. Annual Contribution to the Storm Fund

National Grid's current $4.3 million annual base rate contribution to the storm fund was established in the Company's last rate case. D.P.U 09-39, at 207. The Company proposes to increase the annual base rate contribution to the storm fund by $9.7 million to $14.0 million (Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 4, 26 (Rev. 3)). The Company argues that the current annual contribution of $4.3 million is not sufficient because the number of qualifying events is increasing due to prevailing weather patterns and increased costs associated with the strict emergency response requirements placed on the Company by Massachusetts law and the Department's regulations (Company Brief at 179-180, citing Exh. DPU-32-10). Conversely, the Attorney General argues that a $500,000 increase of the annual contribution to $4.8 million is

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50 GDP-PI sourced from U.S. Bureau of Economic Analysis http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=1&904=2015&903=4&906=q&905=2016&910=x&911=0 (see also Exh. WP-NG-RRP-16).

more appropriate (Attorney General Brief at 99, citing Exh. AG-DO-CF-1, at 29; RR-DPU-50; Attorney General Reply Brief at 53 n.21).

A storm fund is intended to provide a level of rate stability for customers, but only if it actually allows for recovery of storm costs over time without requiring a change to customer rates. As evidenced by the number of major storms since the Company's last rate case and the resulting significant deficit balance in the storm fund, the annual base rate contribution amount of $4.3 million has proven to be insufficient to maintain rate stability. See, e.g., D.P.U. 13-85, at 101, 106 (approving the recovery of costs associated with 16 major storms); D.P.U. 13-59 (approving the recovery of $120 million in storm costs over a three-year period). Thus, we conclude that an increase to the annual base rate contribution to the storm fund is warranted.

In this regard, the Department strives to set a new annual contribution amount that would permit the Company to recover storm costs over time without generating a surplus or deficit balance in the storm fund that would exceed the symmetrical cap.[51] We recognize the uncertainty in achieving this result given the unpredictable nature of the weather in general, and storm events in particular. The Department is in no better position to predict the frequency of future storm events than is the Company or the Attorney General. Further, we acknowledge that while data associated with past major storm events provides a historical perspective regarding the frequency, severity, and costs of major storms, such information is not necessarily predictive of future events. However, notwithstanding these considerations, we conclude that the Company's storm fund history is instructive in the context of setting the parameters for the fund's continuation.

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[51] The symmetrical cap is discussed in further detail below.

The Department has reviewed the record supporting the positions advanced by the Company and the Attorney General (e.g., Exhs. NG-RRP-1, at 69, 85-86; NG-RRP-2, at 26 (Rev. 3); NG-RRP-Rebuttal-1, at 10-11; AG-DO-CF-1, at 29; DPU-21-18; DPU-23-2; DPU-32-1; DPU-32-4, Att.; DPU-32-10; DPU-32-16; DPU-AG-1-19, Att.). Further, the Department has considered the number of major storms that have occurred between the Company's last rate case and the end of the test year; the incremental costs of these storms; the number of storms with incremental costs so high that they should be deemed statistical outliers; and the number of storms that would not have been eligible for storm fund recovery if the cost-per-storm threshold was $1.5 million (Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.). Based on these considerations and our review of the record, we find that setting the annual base rate funding at $10.5 million provides sufficient funds to levelize the rate impact for major storms that are eligible for recovery through the fund while also decreasing the likelihood that the fund will have a large deficiency balance. We find that neither the Company's proposal nor the Attorney General's recommendation achieves an appropriate balance. Therefore, we decline to adopt the Company's proposal or the Attorney General's recommendation.

As noted above, the Company proposes to increase the $4.3 million annual base rate contribution to the storm fund by $9.7 million for a total of $14.0 million (Exhs. NG-RRP-1, at 69, 85 86; NG-RRP-2, at 4, 26 (Rev. 3)). The Department finds that the appropriate level of O&M expense is $10.5 million, which represents an increase of $6.2 million over the test year amount. Accordingly, the Department will reduce the Company's proposed cost of service by $3.5 million ($9.7 million less $6.2 million).

ii. Annual O&M Expense

As noted above, the Company argues that if the Department increases the cost-per-storm threshold to access the storm fund, an increase in the test year amount collected through base rates is warranted (Company Reply Brief at 6 n.4, 74, citing Exh. NG-RRP-Rebuttal-1, at 12; RR-DPU-46; see also Tr. 8, at 1318-1319). During the test year, the Company experienced six major storms that would qualify for storm fund recovery (Exh. DPU-32-4, Att.; Tr. 8, at 1318-1319; RR-DPU-46, Att.). Thus, built into test year O&M is $7.5 million, representing the threshold amount for each storm (i.e., $1.25 million x six major storms) (Tr. 8, at 1318-1319). The Attorney General does not specifically address this issue.

Given that the frequency of storms events varies significantly each year, the test year level of O&M costs associated with storms events may not be representative of the Company's future costs. Therefore, we find that it is appropriate to normalize the level of base rate recovery to derive a more representative amount of O&M expense associated with storm events. This evaluation results in approximately three storms per year qualifying for storm fund recovery (18 storms/6.5 years).[52] Applying a $1.5 million cost-per-storm threshold to each of the three storms yields $4.5 million in O&M costs to be recovered in base rates. This amount is $3.0 million less than the $7.5 million the Company recovered in the test year at the $1.25 million threshold. Further, the Department finds that it is appropriate to include in O&M expense the costs associated with one test year storm (a wind/rain storm in July 2014) that would

[52] Between 2009 and the end of the test year, the four costliest storms were: (1) Tropical Storm Irene in August 2011; (2) the October snowstorm in October 2011; (3) Hurricane Sandy in October 2012; and (4) Nor'easter Nemo in February 2013 (Exh. DPU-32-4, Att.). The additional three storms excluded from consideration were: (1) Hurricane Earl in September 2010; (2) a wind/snow storm in November 2013; and (3) a wind/rain storm in July 2014 (Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.).

not have qualified for storm fund recovery under the $1.5 million threshold and, therefore, would be subject to base rate recovery (see Exhs. NG-RRP-2, at 26 (Rev. 3); DPU-32-4, Att.; see also n.52 above). The cost associated with this one storm (net of Verizon New England, Inc. ("Verizon") billings)[53] is $1,396,743 (RR-DPU-46 & Att.).

As noted, the Company's test year level of O&M expense includes $7.5 million associated with six major storms. The Department has determined that the appropriate level of O&M expense is $5,896,743 ($4,500,000 + $1,396,743). Accordingly, the Department will reduce the Company's proposed cost of service by $1,603,257 ($7,500,000 less $5,896,743).

c. Storm Fund Cap

In the Company's last rate case, the Department determined that to limit the balance in the storm fund that may be used to recover incremental costs from major storms and to prevent the fund from having a deficit balance that is excessive, it was appropriate for the storm fund to have a symmetrical cap (positive and negative) of $20 million. D.P.U. 09-39, at 208. We find that it remains appropriate for the storm fund to continue to have a symmetrical cap on the storm fund balance.

The Company proposes to increase the storm fund's symmetrical cap from $20 million to $30 million to coincide with its proposed increase in the annual base rate contribution for storm costs (Exhs. NG-RRP-1, at 88-89). The Company contends that given recent qualifying storm events, an increase in the symmetrical cap from $20 million to $30 million is a necessary change in order to minimize the potential for frequent rate changes, accommodate the greater level of

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[53] Because of joint ownership of certain facilities, Verizon and the Company share in the cost of storm restoration work. See Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 11-56, at 6 n.9 (2013); D.P.U. 09-39, at 212-213 & n.122.

annual customer contribution proposed in this case, and provide more stable rates for customers (Company Brief at 181, citing Exh. NG-RRP-1, at 89; DPU-21-18). The Attorney General states that if the Department raises the cost-per-storm threshold to $2.4 million and if the customer deposit rate is used to accrue carrying charges on the deficit, the $20 million cap "will likely suffice" (Exh. AG-DO-CF-1, at 29).

In an effort to minimize the potential for frequent rate changes (either positive or negative) and to realign the risks associated with storm cost recovery to protect ratepayers' interests, the Department finds that a symmetrical cap of $30 million on the storm fund balance is appropriate. Further, in order to prevent the storm fund from falling into a significant deficit as the result of a single major storm event, we find that it is necessary to exclude from storm fund eligibility any single storm event that exceeds $30 million in incremental costs (exclusive of Verizon costs). The Company may seek to defer these costs for recovery in its next base rate case. We recognize that given the recent history of storm events, this change to the storm fund mechanism could trigger the filing of a base rate case if multiple storms of a significant magnitude occur during the period in between base rate case filings. However, we find that excluding storms that exceed $30 million in incremental costs, in conjunction with the other modifications approved in this Order, will provide necessary rate stability for customers and help ensure that the storm fund works as intended.

d. Carrying Costs on the Storm Fund Balance

The Company's current storm fund balance accrues interest at the pre-tax WACC, which is 11.48 percent (Exh. NG-RRP-6a at 1). See also D.P.U. 09-39, at 207-208; D.P.U. 09-39-A, at 38. As noted above, the objective of a storm fund is to levelize the cost recovery for major

storms on distribution rates. The use of a storm fund is not intended to shift the financial risk of paying for major storms from electric distribution companies to ratepayers. D.P.U. 09-39, at 205; D.P.U. 10-70, at 200. Rather, it is the Company's allowed ROE that is designed, in part, to recognize these business risks. D.P.U. 09-39, at 205; D.P.U. 10-70, at 200; D.P.U. 1720, at 88-89. Since 2009, the Company has accrued approximately $81 million in interest associated with the costs of the 25 major storms that have qualified for the storm fund (Exh. NG-RRP-6b at 2). We find that a continuation of this result would inappropriately overcompensate the Company for its costs of carrying the storm fund costs. Therefore, the interest rate must be modified.

As noted above, the Company proposes that interest will accrue on incremental storm costs when such costs are filed for recovery with the Department (as opposed to when these costs are incurred) (Exh. NG-RRP-1, at 87). The Company proposes that interest accrue on the combination of the storm fund reserve and the costs related to the storms beginning when filed for storm fund cost recovery (Exh. NG-RRP-1, at 88). If the storm fund balance is in a surplus, then the Company proposes that interest will accrue at a carrying charge rate equivalent to the Company's pre-tax WACC, as determined by the Department (Exh. NG-RRP-1, at 87). Conversely, if the combined storm fund balance is in a deficit, then the amount in deficit (up to the $30 million cap) would accrue interest at the Company's customer deposit rate (Exh. NG-RRP-1, at 88). Further, any storm fund deficit in excess of the proposed $30 million storm cap would accrue interest at a carrying charge rate equivalent to the pre-tax WACC (Exh. NG-RRP-1, at 88).

We find that the Company's proposal for carrying charges to accrue on incremental storm costs when such costs are filed for recovery with the Department will reduce the interest costs paid by ratepayers, and likely will encourage the Company to expedite its filing for cost recovery. Thus, we approve this aspect of the Company's proposal. However, we are not persuaded that the remaining proposed modifications are sufficient to ensure that the carrying costs associated with major storms are appropriately determined. Rather, in order to properly reflect the cost of this balance, the Department finds that the prime rate is a more reasonable carrying charge to be applied to storm fund balances, irrespective of whether the balance represents a surplus or deficit. Accordingly, the Department modifies the carrying charge component of the Company's storm fund. The Company's storm fund shall accrue interest on the combination of the storm fund balance and the costs related to the storms filed for storm fund cost recovery. The interest rate shall be the prime rate,[54] irrespective of whether the storm fund balance represents a surplus or a deficit.

e. Extension of the SFRF and Transfer of the Current Storm Fund Balance

As noted above, in a separate proceeding, the Department extended the SFRF to June 2018 in order to continue collection of the current storm fund balance. D.P.U. 13-85, at 105. National Grid proposes to extend the SFRF an additional 14 months to August 2019, in order to replenish the existing storm fund to account for the nine additional qualifying storm costs that took place after the Company's filing in D.P.U. 13-85, and to minimize the carrying cost associated with those storms (Exhs. NG-RRP-1, at 68-69, 78). Further, the Company proposes to transfer the deficit balance to be collected through the SFRF to a separate regulatory

[54] The prime rate calculated in accordance with 220 C.M.R. § 6.08(2).

asset, and to reset the storm fund balance to zero (Exh. NG-RRP-1, at 78). In addition, the Company proposes that any residual balance (either positive or negative) remaining in the regulatory asset at the end of the extended recovery period (i.e., August 2019) then would be transferred to the Company's storm fund (Exh. NG-RRP-1, at 78-79). Finally, the Company proposes that the regulatory asset continue to accrue interest at the pre-tax WACC (Exh. DPU-21-12, at 1). No parties addressed these matters on brief.

The storm fund mechanism, as modified in the instant case, will be applicable to storms occurring after the date of this Order. Therefore, we find that the Company's proposal to transfer the balance associated with the current storm fund balance to a separate regulatory asset and extend the SFRF an additional 14 months to continue to collecting that balance is reasonable and appropriate. Further, the record demonstrates that under the Company's proposal, customers would benefit from a reduction in carrying charges as a result of extending the SFRF through August 2019 (Exh. DPU-18-2). The Company estimates the reduction of interest at approximately $19.7 million (Exh. DPU-18-2). Additionally, we find it appropriate to transfer any residual balance to the storm fund at the end of the extended recovery period. Based on these considerations, we approve the Company's proposal.

4. Conclusion

Based on the above findings, the Department directs the Company to continue its storm fund with the modifications set forth herein. The modified storm fund shall apply to any qualifying storms that occur after the date of this Order.

The current storm balance shall be recovered through August 2019 consistent with the findings above. Further, consistent with the Department's findings in D.P.U. 13-85, at 105, the

Department directs the Company to file as part of its compliance filing in this case a revised Storm Fund Replenishment Provision tariff to replace M.D.P.U. 1292.

Finally, consistent with the findings above, the Department has reduced the Company's proposed cost of service by (1) $3.5 million relative to the annual base rate contribution to the storm fund, and (2) $1,603,257 relative to the annual amount in base rates to cover costs up to the cost-per-storm threshold and for smaller storm events that do not qualify for the storm fund. These reductions are shown as combined adjustments on the Department's Schedules.

VII. RATE BASE

A. Overview

The Company's test year rate base was $1,760,316,969, based on a total net utility plant in service of $4,084,097,215 (Exh. NG-RRP-2, at 30 (Rev. 3)). To this amount, the Company proposes to add $39,210,328 in rate base adjustments for a total proposed rate base of $1,799,527,297 (Exh. NG-RRP-2, at 30 (Rev. 3)). The Company's total proposed rate base consists of: $2,307,263,848 in net utility plant in service, $23,231,040 in net materials and supplies, and $68,019,916 in cash working capital; less, $569,147,565 in deferred income taxes and $29,839,942 in customer deposits (Exh. NG-RRP-2, at 30 (Rev. 3)).[55]

B. Plant Additions

1. Introduction

In D.P.U. 09-39, the Department approved the current CapEx mechanism, which allows recovery of the revenue requirement associated with the Company's annual capital expenditures, net of the amount recovered in base rates through depreciation expense. D.P.U. 09-39, at 79, 82.

[55] Minor discrepancies in any of the amounts appearing in this section are due to rounding.

The Department capped the amount of capital spending the Company could recover through the CapEx mechanism based on an annual investment of $170 million. D.P.U. 09-39, at 82.[56] Pursuant to D.P.U. 09-39, the Company files a Capital Investment Report ("CapEx filing") by July 1st of each year containing information and project documentation relating to the capital placed in service during the prior calendar year ("CY"). D.P.U. 09-39, at 85. By November 1st of the filing year, the Company must file its CapEx factors that incorporate the costs associated with the capital placed in service, up to the allowed cap, into a rate adjustment effective March 1st of the following year. D.P.U. 09-39, at 85.

From 2010 through 2015, National Grid made annual CapEx filings and proposed annual CapEx factors to recover capital additions made in 2009 through 2014, up to the allowed cap. The Company's annual CapEx filings were docketed as D.P.U. 10-79 (2009 CY additions), D.P.U. 11-60 (CY 2010 additions), D.P.U. 12-48 (CY 2011 additions); D.P.U. 13-84 (CY 2012 additions), D.P.U. 14-95 (CY 2013 additions), and D.P.U. 15-84 (CY 2014 additions). The Company's CapEx mechanism is a component of the Company's RDM tariff and, therefore, the CapEx factors were filed as part of the Company's RDM filings.[57]

During the pendency of the first CapEx filing, D.P.U. 10-79, the Attorney General, pursuant to G.L. c. 25, § 5, requested an independent audit of the Company's record keeping,

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[56] While the Department limited the Company's allowed recovery under CapEx mechanism to $170 million, we made no determination on how much capital investment the Company should make. D.P.U. 09-39, at 82-83. The Department found that if National Grid's capital expenditures exceeded the amount it could recover through its CapEx mechanism, the Company could seek to include such investment in rate base in its next base rate proceeding. D.P.U. 09-39, at 82-83.

[57] The RDM filings were docketed as D.P.U. 10-152, D.P.U. 11-117, D.P.U. 12-115, D.P.U. 13-175, D.P.U. 14-136, and D.P.U. 15-154.

accounting practices, and process for developing the filing, which was docketed and commenced in D.P.U. 11-18. Audit of National Grid's Calendar Year 2009 Capital Investment Program, D.P.U. 11-18-F at 1 (2016). The Department allowed the Company to recover its proposed revenue requirement through the CapEx factors, subject to further investigation, and placed the prudency review in D.P.U. 10-79 on hold during the pendency of the audit. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-152, at 5 (2011); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-79, Interlocutory Order on Filing Requirements at 5-7 (June 14, 2011) ("D.P.U. 10-79 Interlocutory Order"). In light of the concerns giving rise to the Attorney General's audit request, the Department also issued filing guidelines for future CapEx filings to be made during the pendency of the audit. D.P.U. 10-79 Interlocutory Order at 5-7. The audit was completed in 2015 and the Department issued a final Order accepting the final audit report on February 26, 2016. D.P.U. 11-18-F.[58] Consistent with the process for D.P.U. 10-79, the Department allowed the Company to recover its proposed revenue requirement, subject to further investigation, through the CapEx factors[59] for each subsequent year that the audit was pending, but placed the prudency review of all capital

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58 The auditor found an adjustment of $1.2 million, which the Department directed the Company to correct in this proceeding. D.P.U. 11-18-F, at 15.

59 As noted above, the CapEx factors were filed as part of the following RDM filings: Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-117, at 2 (2012); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 12-115, at 3 (2013); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-175, at 4 (2014); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136, at 3 (2015); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-154, at 4 (2016).

investments on hold during the pendency of the audit.[60] In summary, the Department allowed the Company to recover its proposed revenue requirements associated with the capital additions made from 2009 through 2014 subject to further investigation, but did not fully adjudicate the CapEx filings, made no findings that the associated capital additions were prudent and used and useful, and did not issue any final Orders while the audit was pending. Thus, the Company, in this rate case, seeks a determination of the prudence and used and usefulness of the capital additions that were the subject of the annual CapEx filings for investment years 2009 through 2014, plus any capital additions during those years that exceeded the $170 million cap, as well as capital additions placed in service in the first six months of 2015 (the second-half of the test year in this proceeding), in order for those additions to be included in rate base (Exh. NG-JHP-1, at 13-14).[61]

2. Investment Activity

From January 1, 2009 through June 30, 2015, National Grid completed $1,189,550,456 in plant additions and incurred $93,778,658 in cost of removal, which resulted in an increase in utility plant of $1,283,329,114 (Exhs. DPU-10-6, Att.; AG-7-5, Att.; RR-DPU-12; RR-DPU-13, Att.).[62] National Grid identified 1418 capital projects that were completed during this period

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60 The following CapEx dockets were placed on hold: D.P.U. 11-60; D.P.U. 12-48; D.P.U. 13-84; D.P.U. 14-95; D.P.U. 15-84.

61 In the absence of the CapEx mechanism, the Company would have sought inclusion in rate base of all capital additions placed in service since its last rate case, which is effectively what the Company seeks now because the CapEx filings were not fully adjudicated.

62 The Company's investment activity is broken down as follows: (1) $463,986,528 for 62 blanket projects; (2) $217,111,440 for 100 program projects; (3) $509,652,488 for 1,253 specific projects; and (4) a $1,200,000 negative adjustment to reflect an error for a double

(Exhs. DPU-7-23, Att. (Rev.); DPU-7-23, Att. (Supp.); RR-DPU-12). National Grid groups its capital projects into three categories: (1) specific projects, (2) blanket projects, and (3) program (or other annual) projects (Exh. NG-JHP-4, at 1). As part of its initial filing in this case, the Company provided the filings made in each of the previous CapEx dockets as well as documentation relating to the first six months of 2015. For each project the Company seeks to include in rate base, the Company also provided a spreadsheet with the project number, a brief project description, the total amount authorized, the total amount expended, and the total amount closed to plant (Exh. DPU-7-23, Att. (Rev.)). As discussed below, the Attorney General challenges the sufficiency of the documentation provided for 20 specific projects, two storm program projects, 32 blanket projects, and 47 program projects (Attorney General Brief at 12-19).

3. Project Documentation

With exceptions noted below, the Company provided the following documentation for specific projects over $50,000 and for all blanket and program projects: (1) a project summary sheet that includes project number, project descriptions, approved amount, total to date project spending, project status, approval history, and in-service additions and cost of removal figures; (2) a project approval report showing approval amounts and dates and screen-prints from the PowerPlan system;[63] (3) documentation relating to the approved amounts (such as walk-in

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charge to the Company for the cost of materials associated with a limited subset of capital work that was subcontracted out to third parties in 2009 through 2012 (RR-DPU-12).

63 Screen-prints may also be from older systems including PowerPlant and Primavera Portfolio Management (Exh. NG-JHP-4, at 3).

documents, re-approval forms, distribution capital investment group papers,[64] United States Sanctioning Committee ("USSC")[65] sanction papers, and study documents); (4) a retirement report showing any retirements related to the project in the relevant year; (5) a direct/indirect summary report for in-service asset additions showing project-level costs for property placed in service during the relevant year; (6) a work order asset addition report showing closings to plant in-service; and (7) a project cost summary showing project spending for a given year (see, e.g., Exhs. NG-JHP-3; NG-JHP-4). For blanket and program projects the Company also provided a fiscal year variance analysis report and a fiscal year closure paper (Exh. NG-JHP-4, at 12, 13).[66]

4. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that the Company failed to provide clear and reviewable documentation demonstrating the prudence of its capital additions for $56 million in variances

64 This group is an executive management group that approves projects with projected scope and costs above established thresholds (Exh. NG-JHP-3(a) at 12 (prefiled testimony)).

65 The USSC is a group within National Grid USA that provides executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization (RR-DPU-43, Att. 3, at 17).

66 As described more fully below, the Company did not initially provide blanket project closure papers for fiscal years 2013 and 2014. Further, the Company initially did not provide closure papers for six program projects over $1 million or reauthorization forms for 14 program projects over $100,000.

(Attorney General Brief at 11, Attorney General Reply Brief at 12).[67] Specifically, the Attorney General contends that the Company failed to provide: (1) adequate explanations for 20 specific projects that had cost variances totaling $6.5 million; (2) adequate variance explanations for two storm capital program projects,[68] with cost variances totaling $11.7 million; and (3) closing papers and documentation for 31 blanket and 47 program projects with unfavorable cost variances totaling $37.8 million (Attorney General Brief at 11, 14, 19; Attorney General Reply Brief at 12). Therefore, the Attorney General claims that the Department should exclude $56 million from the Company's rate base because it did not meet its burden of demonstrating the propriety of these additions to rate base (Attorney General Brief at 11; Attorney General Reply Brief at 6). The Attorney General asserts that the Company bears the burden of demonstrating the propriety of additions to rate base through clear and cohesive reviewable evidence and cannot simply provide a "cascade" of documents and point to the overall volume as evidence of prudence (Attorney General Reply Brief at 8, citing D.P.U. 14-150, at 42–43 (2015)).

Further, the Attorney General challenges the Company's claims that its capital budgeting and authorization processes is evidence of "reasonable mechanisms to control costs and manage

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67 In her initial brief, the Attorney General sought disallowance of $68.6 million that included $50.4 million in blanket and program costs. The $50.4 million amount included 27 program projects, or $18.2 million, and 32 blanket projects, or $32.2 million (Attorney General Brief at 11-19). On reply, the Attorney General reduced this amount by $12.6 million, the amount of one blanket project (CBS0004), due to an accounting error that the Company corrected (Attorney General Reply Brief at 6, citing Company Brief at 123).

68 On brief the Attorney General and the Company both refer to the storm projects as storm capital "blanket" projects, but these storm projects appear on the Company's list of program projects and in the program project variance analysis reports (see, e.g., Exhs. DPU-7-23, Att. (Supp.); NG-JHP-3(e), JLG-8, at PGRM-1190). Hereinafter, we refer to these storm projects as program, not blanket, projects.

projects within established budget parameters" with respect to blanket and program projects because the Company did not follow its own procedures for cost management and control (Attorney General Reply Brief at 7, citing Company Brief at 119). Specifically, with respect to blanket projects the Attorney General contends that the Company did not prepare closure papers at the end of the fiscal year ("FY"), upon the actual closure of those projects in FYs 2013 and 2014 (Attorney General Reply Brief at 8, citing Company Brief at 118). Instead, the Attorney General claims that the Company created the documentation years after the closure of the projects, on April 26, 2016, following multiple requests by the Department and the Attorney General for their production (Attorney General Reply Brief at 8, citing Exhs. DPU-20-1 through DPU-20-82; DPU-20-31 (Supp.); DPU-20-35 (Supp.); AG-21-1). Similarly, the Attorney General argues that the Company did not complete closure papers and/or final cost documentation for program projects in FYs 2013 and 2014, as well as for several projects in fiscal year 2015, until after the close of the evidentiary hearings in this proceeding (Attorney General Reply Brief at 8, citing Exh. NG-JHP-Rebuttal-1, at 20; Tr. 3, at 435–36). The Attorney General, therefore, asserts that the timing of the completion of this documentation calls into question the efficacy of the Company's process to control costs and, moreover, the prudency of the Company's capital expenditures related to these blanket and program projects (Attorney General Reply Brief at 8).

ii. Specific Projects

The Attorney General argues that the Department should exclude $6.5 million in variance amounts relating to 20 specific projects for which the Company did not provide variance

explanations (Attorney General Brief at 11-12).[69] The Attorney General contends that the Department specifically sought information relating to the cost over-runs, but that the Company did not provide any explanations (Attorney General Brief at 11-12). Instead, the Attorney General claims that the Company simply cited to its own internal policies to: (1) provide a variance explanation only when project costs differ by more than ten percent; and (2) consider only the combined variance of projects managed as part of the same effort, rather than to provide the variances associated with each project (Attorney General Brief at 13-14). The Attorney General asserts that the Company's reliance on its internal policies is insufficient because the Department has specifically held that "a company's internal project cost estimation policies cannot . . . override, the company's obligation to demonstrate to the Department the prudence of its capital project costs" (Attorney General Brief at 14, citing D.P.U. 14-150, at 87). The Attorney General, therefore, recommends that the Department exclude $6.5 million from rate base because the Company failed to carry its burden of production with respect to these cost variances (Attorney General Brief at 14, citing D.T.E. 03-40, at 52, n.31; D.T.E. 01-56-A at 16).

iii. Storm Capital Programs

The Attorney General argues that the Department should disallow $11.7 million in cost variances related to two storm programs because the Company failed to provide an explanation for the cost variances that occurred during FYs 2010 and 2012 (Attorney General Brief at 19, citing Exhs. DPU-19-1; DPU-19-2). The first program includes two FY 2010 projects, C014821

[69] These projects include: C008666; C005339; C014549; C023591; C036385; C028886; C002364; C002388; C012018; C012502; C024120; C005342; CD01253; C001423; C028871; C029104; C031552; CD01174; C031324; C002504 (Attorney General Brief at 12).

and C014822, totaling a $2.4 million variance (Attorney General Brief at 19-20).[70] The second program includes one FY 2012 project, C014821, with a $9.3 million variance (Attorney General Brief at 20). The Attorney General claims that the Company's closure papers do not explain the reason for the cost overruns, and that the Company has evaded any adequate explanation as requested, and required, by the Department (Attorney General Brief at 20). Further, with respect to the FY 2012 variance, the Attorney General asserts that the Department conducted an investigation into the subject storms, found that the Company acted imprudently, and imposed substantial fines (Attorney General Brief at 20, citing D.P.U. 11-85-A/D.P.U. 11-119-A). Further, the Attorney General asserts that although the Company could not predict restoration costs, it should "honor the spirit of its own processes," which contemplate that variance analyses can contribute to "lessons learned" (Attorney General Reply Brief at 10-11, n.6, citing Company Brief at 118-119). The Attorney General, therefore, recommends that the Department exclude from rate base the $11.7 million variance for these storm program projects (Attorney General Brief at 20).

iv. Blanket & Program Projects

The Attorney General argues that the Department should exclude from rate base $37.8 million in cost variances, $18.2 million for 47 program projects,[71] and an additional $19.6

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70 These projects are titled "BSW Storm Cap Confirm Proj" and "N&G Storm Cap Confirm Proj," respectively.

71 These projects include: C005490; C005500; C005432; C005543; C005563; C006642; C005439; C005441; C005444; C005449; C016492; C005469; C005475; C005480; C059664; C006138; C028147; C032015; C032016; C032018; C033822; C025810; C032270; C032272; CD00017; C025619; C014821; C021594; C022216; C022217; C016120; C016121; C018594; CD00259; C025326; C025813; C027898; C027927;

million for 31 blanket projects[72], because the Company failed to carry its burden to show that these cost variances were prudently incurred (Attorney General Brief at 15). As an initial matter, the Attorney General contends that the Company did not comply with the D.P.U. 10-79 Interlocutory Order, which required the Company to produce as part of its initial filing "project details for capital projects placed in service costing more than $50,000, including the project cover sheet, approved amount, actual cost, cost variance information, and other applicable documentation such as the appropriate number of units associated with the actual capital placed in service, project sanction, re-sanction, and closure papers" (Attorney General Brief at 14, citing D.P.U. 10-79 Interlocutory Order at 7 n.3). Despite this filing requirement, the Attorney General claims the Company failed to provide in its initial filing closure papers for all of the program and blanket projects in FYs 2013 and 2014, as well as several program projects for FY 2015 (Attorney General Brief at 15).

Further, the Attorney General challenges the Company's eventual production of the requisite documentation relating to blanket projects (filed on May 3, 2016) and program projects (filed on June 2, 2016) as untimely (Attorney General Brief at 16-18). With respect to the blanket projects, the Attorney General argues that National Grid failed to provide the aforementioned documentation during discovery and filed them on May 3, 2016, just twelve hours before the Company's plant additions witness was scheduled to testify (Attorney General

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C031398; C031774; C032024; C035584; C049352; C032572; C033764; C033765; CD01258.

[72] These projects include: CBN0002; CBN0004; CBN0010; CBN0011; CBN0012; CBN0014; CBN0015; CBN0016; CBN0017; CBN0022; CBS0010; CBS0011; CBS0014; CBS0020; CBS0022; CBW0002; CBW0006; CBW0010; CBW0011; CBW0014; CBW0016; CBW0020; CN00420; CNM0002; CNM0004; CNM0010; CNM0011; CNM0014; CNM0017; CNM0020; CNM0022.

Brief at 18). According to the Attorney General, due to the volume and nature of the documents, she did not have any time to conduct discovery or review the material in order to effectively cross-examine the Company's witness (Attorney General Brief at 18, citing D.P.U. 14-150, at 49; D.P.U. 10-70, at 194 n. 98, 200). Accordingly, the Attorney General recommends that the Department exclude from rate base $19.6 million in blanket projects' variances for which the Company failed to timely file closure papers (Attorney General Brief at 18).

With respect to the program projects, the Attorney General asserts that the closure papers for the program projects in question, if filed at all, were filed late on June 2, 2016 (Attorney General Brief at 16). As discussed in the next section below, the Attorney General moved to strike this documentation from the record, and urged the Department not to consider them (Attorney General Brief at 16). Accordingly, the Attorney General recommends that the Department exclude from rate base $18.2 million in program projects' variances for which the Company failed to timely file closure papers (Attorney General Brief at 16).

The Attorney General rejects any notion that she seeks disallowance of the aforementioned costs because "a piece of paper is missing from the file . . . ." (Attorney General Reply Brief at 9, citing Company Brief at 123). She argues that this mischaracterization trivializes both the Company's management process and the prudency review process conducted by the Department in this rate case (Attorney General Reply Brief at 9, citing Company Brief at 123). The Attorney General contends that she did not target project costs for disallowance because one piece of paper was missing, but because variance amounts were not supported by the documentation that the Company itself claims is used to "note reasons for any overspending

during the fiscal year and [detail] the Company's actions to keep overall capital spending within budgeted amounts" (Attorney General Reply Brief at 9, citing Exh. AG-DO-CF-1, at 52–53).

Further, the Attorney General argues that the late filing of the closure papers is not inconsequential, as it relates to the Company's burden to provide, at a minimum, documentation that allows the Department to evaluate the prudence of each of the capital projects, and to make a determination that each project was placed in service during the test year and is used and useful (Attorney General Reply Brief at 9, citing Company Brief at 123; Bay State Gas Company, D.P.U. 13-75, at 105 (2014); Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 8 (2001)).[73]

b. Company

i. Introduction

National Grid argues that the record contains sufficient evidence for the Department to find that the capital additions submitted for approval in this proceeding were prudently incurred and are used and useful in providing service to customers (Company Brief at 113). The Company claims that it provided actual computations and thousands of pages of supporting documentation including: project cover sheets; approved amounts; actual costs; cost variance information' project sanction, re-sanction, and closure papers; and a detailed explanation of the processes that the Company uses to manage both the allocation and cost of capital expenditures

[73] The Attorney General argues that in several instances the Company provided documentation in April, May, or June, after the discovery deadline had passed and testimony had been filed, and, therefore, too late for the Department, the Attorney General, or other intervenors to conduct a thorough and probative evaluation of the contents of the documentation for prudency purposes (Attorney General Reply Brief at 9-10, citing Exhs. NG-JHP-Rebuttal-2 (filed April 19, 2016); DPU-20-31 (Supp.), DPU-20-35 (Supp.) (filed May 3, 2016); NG-JHP-Rebuttal-2 (Supp.) (filed June 2, 2016)).

(Company Brief at 113, citing Exhs. NG-JHP-1, at 9, 21-23; NG-JHP-3; NG-JHP-4; NG-JHP-Rebuttal-2; NG-JHP-Rebuttal-2 (Supp.); DPU-20-31 through 20-53 (Supp.)).

The Company also argues that its capital budgeting and authorization process assures cost containment (Company Brief at 119). The Company contends that it conducts a detailed, multi-tiered capital-planning process to control costs and manage projects within the established budget parameters (Company Brief at 115, citing Exh. NG-JHP-1, at 21-23). Specifically, the Company points to its Delegation of Authority ("DOA") and Sanctioning/Re-sanctioning policies for projects with costs under $1 million and at or above $1 million as reasonable mechanisms to control costs and manage projects within the established budget parameters (Company Brief at 116-118, citing RR-DPU-43, Atts. 2, 3). Further, the Company argues that its Capital Funding Project Overrun Report is the primary vehicle employed for cost-control purposes (Company Brief at 119). According to the Company, this monthly report identifies the funding projects that have exceeded or are forecasted to exceed the authorized DOA amount, after which the responsible individual must complete a written plan to bring the affected funding project within DOA limits within ten days and seek management re-sanction of those funding projects that exceed the authorized spending limit no later than 60 days after notification (Company Brief at 115, 119, citing RR-DPU-43, Atts. 2, 3).

Further, the Company contends that the Attorney General's argument relating to the timing of filing certain documents amounts to form over substance, does not raise a challenge to the prudence or used and usefulness of any capital project, and is insufficient to justify disallowance of $56 million in capital investment costs (Company Brief at 123, 128; Company Reply Brief at 16). The Company contends that there is no requirement for a petitioner to

present every piece of paper associated with a project in the initial filing, and that no additional document can be provided during the case or the project is subject to disallowance (Company Brief at 123). Thus, the Company asserts that the Department should not disallow the costs of substantial work projects put in place for the benefit of the distribution system on the basis that a piece of paper is missing from the file, rather than on the basis of any inquiry into the nature, scope, conduct or completion of the project (Company Brief at 123-124).

ii. Specific Projects

The Company argues that it has provided detailed information for all specific projects as required under the standard for inclusion in rate base, which demonstrate that the capital additions were prudently made and are used and useful (Company Brief at 119, citing Exh. NG-JHP-1, at 9-11).[74] The Company contends that for specific projects costing more than $50,000, it provided: the project cover sheet; approved amount; actual cost; cost variance information; the appropriate number of units associated with the actual capital placed in service; and project sanction, re-sanction, and closure papers (Company Brief at 119, citing Exh. NG-JHP-1, at 9-11). Further, the Company claims that all 20 of the projects have variances of less than ten percent (Company Reply Brief at 17). In this regard, the Company notes that its policy is to evaluate and document project cost variances only if the aggregate costs of the suite of funding projects exceeds "tolerance," which for these projects was ten percent (Company Brief at 124; Company Reply Brief at 17). Further, the Company argues that it

[74] Of the $6.5 million for which the Attorney General recommends exclusion, the Company argues that approximately $3.2 million is attributable to O&M expenditures, and another $1.2 million represents costs incurred on funding projects that are not yet placed in service, and, therefore, are not part of the Company's rate base request (Company Brief at 122).

submitted to the Department documentation including variance analyses with the Company's rebuttal testimony on April 19, 2016 (Company Reply Brief at 17, citing Exh. NG-JHP-Rebuttal-2). Therefore, the Company asserts that the Department should reject the Attorney General's recommended disallowance (Company Brief at 124; Company Reply Brief at 17-18).

iii. Storm Capital Programs

The Company argues that it provided sufficient variance explanations regarding these programs to warrant recovery of the $11.7 million in costs recommended for disallowance by the Attorney General (Company Brief at 127, Company Reply Brief at 19). In this regard, the Company contends that for storm programs it uses a budgetary method used to set aside a dedicated amount of money each year for mandatory work necessary to restore power after significant storm damage (Company Brief at 127). The Company contends that because storms are unpredictable, it is prepared to overspend the budgeted amounts to complete restoration efforts as necessary (Company Brief at 127). Thus, the Company asserts that any failure to explain why it was unable to accurately predict restoration costs is not a legitimate basis for disallowance (Company Brief at 127). Moreover, the Company notes that the Attorney General first challenged the variance explanations on brief, after having had substantial opportunity to inquire about an explanation provided nearly four years ago in the Company's CapEx filing in D.P.U. 12-48, and again in the Company's initial filing in this proceeding (Company Brief at 128, citing Attorney General Brief at 20).

iv. Blanket and Program Projects

The Company disagrees with the Attorney General's assertion that the late filing of documentation relating to blanket and program projects is a valid basis for disallowing $37.8 million in blanket and program projects (Company Brief at 125). The Company argues that its closure papers adequately support inclusion of the program and blanket projects in rate base (Company Brief at 125). Specifically, the Company contends that it is not required to anticipate and provide with the initial filing the entire evidentiary record in support of each component of its rate filing because it is the function of the adjudicatory process to establish an evidentiary record upon which the Department can base a decision on the matters at issue (Company Brief at 125). Further, the Company notes that it did include in its initial filing both summary and project-specific documentation for every project over $100,000, and that this documentation provided more than sufficient information to facilitate the efficient conduct of the proceeding (Company Brief at 125, citing Exhs. NG-JHP-3; NG-JHP-4).

In addition, the Company argues that it submitted the majority of the closure papers sought by the Attorney General on May 3, 2016, after providing notice in rebuttal testimony of its intent to make the supplemental filing (Company Brief at 126, citing Exhs. NG-JHP-Rebuttal-1, at 19; NG-JHP-Rebuttal-2). The Company notes that the Attorney General did not object to the Company's production plan (Company Brief at 126).

5. Analysis and Findings

a. Motion to Strike

i. Introduction

The Hearing Officer adjourned hearings on May 26, 2016 (Tr. 15, at 1695). On June 2, 2016, National Grid filed a supplemental response to information request DPU-7-23 and a supplemental attachment to the rebuttal testimony of one of its witnesses (Exhs. DPU-7-23 (Supp.); NG-JHP-Rebuttal-2 (Supp.)). On June 10, 2016, the Attorney General filed a motion to strike these documents as extra-record information. On June 17, 2016, National Grid filed a response to the Attorney General's motion to strike.

Exhibit DPU-7-23 (Supp.) contains an additional worksheet showing that certain of the Company's capital projects are part of a larger group of projects. Exhibit NG-JHP-Rebuttal-2 (Supp.) contains reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015.

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the documents filed on June 2, 2016,[75] constitute extra-record evidence for which the Company is required to file a motion to reopen the record and make a showing of good cause pursuant to 220 C.M.R. § 1.11(8) (Attorney General Motion at 1, 2). Further, she contends that the Department has made clear that, except for updates to routine information already provided in the record (e.g., property tax bills) a motion to reopen the record must be filed and granted before the testimony or exhibits are "thrust upon the trier of

[75] The Attorney General contends that the information provided was voluminous, provided additional final cost information for certain blanket and program costs, and contained substantial changes to previously filed record evidence (Attorney General Motion at 1).

fact," noting that "one cannot unring a bell" (Attorney General Motion at 2, quoting Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989)). Thus, the Attorney General asserts that if the Department allows the subject documents into the record, it will deny the Attorney General's and other intervenors' due process rights to conduct discovery and cross-examination,[76] and will result in rates that are not just and reasonable (Attorney General Motion at 1-4, citing G.L. c. 30A § 11(3); 220 C.M.R. §§ 1.11; D.P.U. 10-70, at 195-96; MediaOne/New England Telephone, D.T.E. 99-42/43, p. 17-18 (1999); Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 9 (1998); New England Telephone and Telegraph Company, D.P.U. 94-50, at 62 (1995); Boston Edison Company, D.P.U. 90-335, at 7-8 (1992); Payphone Inc., D.P.U. 90-171, at 4-5 (1991)).

Further, the Attorney General argues that even if the Company had filed a motion to reopen the record, it could not have made a showing of good cause because much of the supplemental material concerned activity that occurred several years ago and should have been filed with the Company's initial filing (Attorney General Motion at 3, citing D.P.U. 14-150, at 50). Additionally, she notes that the Company failed to timely provide the subject documentation in response to information requests issued during the proceedings (Attorney General Motion at 3, citing Exhs. DPU-7-23; AG-21-2). The Attorney General further asserts that "good cause" is an important safeguard to intervenors' procedural due process rights and that no good cause can exist for the late-filing of these materials because the Company had

[76] The Attorney General also argues that because the Company filed the Supplemental Material so close to the briefing deadline, the Attorney General did not have adequate time for even a cursory review of the documents prior to filing briefs (Attorney General Motion at 1, citing D.P.U. 10-70, at 195-196).

ample time and multiple opportunities to supply the supplemental materials (Attorney General Motion at 3).

(B) Company

National Grid argues that the evidentiary record did not close on May 26, 2016, because the Department made provisions for the Company to provide the subject documentation after the conclusion of evidentiary hearings (Company Response at 3). Specifically, the Company argues that during the May 3, 2016, evidentiary hearing, the Hearing Officer recognized that the Company provided some of its closure papers with its rebuttal testimony, but that some had not been compiled (Company Response at 3, citing Tr. 3, at 435). The Company argues that the Hearing Officer then issued Record Request DPU-13 for the Company to update its blankets and programs plant additions with actual cost information once the remaining closure papers were completed (Company Response at 3, citing Tr. 3, at 438). Additionally, National Grid claims that the Hearing Officer accepted the Company's representation that the actual cost information for blanket and programs would not be known until June 1, 2016, and, therefore, extended the due date for the Company's response to Record Request DPU-13 from May 12 to June 1, 2016 (Company Response at 3, citing Tr. 3, at 435-336, 438). Thus, National Grid argues that the Hearing Officer explicitly left the evidentiary record open for the production of this documentation, and the Company provided the information in conjunction with the supplemental attachment to the rebuttal testimony and the response to Record Request DPU-13 (Company Response at 5). Accordingly, the Company argues that it was not required to file a motion to reopen the record (Company Response at 5).

Further, the Company argues that even if the Hearing Officer had not left the evidentiary record open to receive the subject documentation, the Attorney General fails to cite any Department decision, regulation or rule to support the notion that the evidentiary record is closed on the last day of evidentiary hearings, absent specific exceptions or requests to keep open the record (Company Response at 4). According to the Company, it is the Department's long-standing practice to keep the record open after the close of evidentiary hearings for admission of information relevant to its determinations, including specified updates to schedules and responses to record requests (Company Response at 4, citing Cambridge Electric Light Company, D.P.U. 92-250 (1993); The Berkshire Gas Company, D.P.U. 90-121 (1990)).

Moreover, the Company argues it has a continuing obligation to update the record if it obtains new information pertinent to the proceeding and is also under a continuing obligation to "seasonably amend its responses to discovery, direct examination, and cross-examination as soon as it obtains information that a response was incorrect or incomplete or that a response, though correct when made, is no longer true or complete" (Company Response at 5, quoting Bay State Gas Company, D.P.U. 12-25, at 106-107 (2012); citing 220 C.M.R. § 1.06(6)(c)(5); D.P.U. 09-30, at 174; D.T.E. 02-24/25, at 32-33; Riverside Steam and Electric Company, D.P.U. 88-123-B at 57-58 (1991); Aquarion Water Company of Massachusetts, D.P.U. 08-27-B at 22 (2010)). The Company contends that this obligation continues beyond evidentiary hearings and even after a base rate case proceeding has concluded (Company Response at 5, citing D.P.U. 12-25, at 106-107). In this regard, National Grid claims that capital project documentation, relevant to the Department's review of the Company's petition, should be

accepted into evidence even if filed after the close of evidentiary hearings and unaccompanied by a motion to reopen the record (Company Response at 6, citing D.P.U. 10-55, at 190).

Finally, the Company argues that accepting the subject documentation into the record would not prejudice the Attorney General (Company Response at 6). The Company contends that most of its closure papers supporting the blanket and program capital projects were filed in its rebuttal testimony (Company Response at 6, citing Exhs. NG-JHP-Rebuttal-1, at 19-20). Further, National Grid asserts that the Attorney General had adequate notice of the Company's intention to file supplemental closure papers after the conclusion of evidentiary hearings and should have raised any concerns at the May 3, 2016 evidentiary hearing when reasonable accommodations could have been made to the briefing schedule (Company Response at 7).

iii. Analysis and Findings

First, the Department will not strike Exhibit DPU-7-23 (Supp.) because we find that it simply was an alternative presentation of an earlier version of the response, modified to show which specific projects were part of larger groups (compare Exh. DPU-7-23, Att. (Rev.) with Exh. DPU-7-23, Att. (Supp.)). In addition, in the supplemental response to information request DPU 7-23, the Company replicated its response to Record Request DPU-12 and separated the total investment for specific projects into two amounts – one for standalone specific projects and one for specific projects that were part of a group (compare Exh. DPU-7-23, Att. (Supp.) with RR-DPU-12). The total number of projects, the cost information for the projects, and the associated revenue requirement did not change with the filing of the supplemental response to information request DPU 7-23 (Exhs. DPU-7-23, Att. (Rev.); DPU-7-23, Att. (Supp.); NG-RRP-2; NG-RRP-2 (Rev. 3); RR-DPU-12).

However, unlike the materials contained in Exhibit DPU-7-23 (Supp.), the documentation filed with Exhibit NG-JHP-Rebuttal-2 (Supp.) does contain an additional eighty pages of reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015, that were not previously provided earlier in the docket (Exh. NG-JHP-Rebuttal-2 (Supp.)). Given that these documents were filed a full week after evidentiary hearings ended, and that there was no valid explanation offered as to why these documents were not produced prior to that time given multiple requests for the type of information included herein, neither the Department nor the intervening parties had the opportunity to inquire about them through discovery or cross examination.

Further, despite the Company's argument to the contrary, we find that the record was not left open, either expressly or implicitly, for the production of these documents. At the close of evidentiary hearings, the record was left open for the production of specific information that did not include the subject documentation (Tr. 15, at 1691-1693). Additionally, the Hearing Officer's inquiry earlier in the hearings regarding the status of documents did not constitute a ruling on the propriety of allowing the information into the evidentiary record (Tr. 3, at 435). Further, we find that the Hearing Officer's issuance of Record Request DPU-13 was in no way related to the production of the subject documents. This Record Request asked the Company to update information, which previously was provided in the response to Exhibit AG-7-5, regarding annual capital expenditures since 2009 (Tr. 3, at 436-438). The Hearing Officer did not include in this record request any specific project documentation for any capital additions, let alone the subject documents that ultimately were filed on June 2, 2016 (Tr. 3, at 436-438).

Additionally, we note that the documents filed with Exhibit NG-JHP-Rebuttal-2 (Supp.) should have been produced with the initial filing in this case, particularly those documents that pertain to investments that were placed in service in 2013 and 2014. At a minimum, these materials should have been made available in response to the discovery process that occurred prior to evidentiary hearings, or during the filing of rebuttal testimony, once it became known that these materials were still omitted from the case. Pursuant to the Company's own capital authorization policies, these documents should have been completed at the close of the fiscal years for 2013 and 2014, and available well in advance of their filed date (RR-DPU-43, Atts. 2-3). Further, these documents should have been provided as part of the Company's annual CapEx filings in July 2014 and July 2015.

Based on these considerations, we conclude that the reauthorization documents and closure papers for certain program projects placed in service in FY 2013, 2014, and 2015, produced on June 2, 2016, in Exhibit NG-JHP-Rebuttal-2 (Supp.), were not timely filed. Further, we find that the Attorney General was precluded from conducting a meaningful review of these documents and from inquiring about the specific program projects either through discovery or cross examination. Consequently, the Department allows the Attorney General's motion to strike and will not consider these documents in the determination of whether these projects qualify for inclusion in the Company's rate base.

b. Plant Additions

i. Standard of Review

For costs to be included in rate base the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company,

D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Boston Gas Company/Colonial Gas Company/Essex Gas

Company, D.P.U. 10-55-B at 13-16 (2013); D.P.U. 09-30, at 144-145; Boston Gas Company, D.P.U. 96-50 (Phase I) at 21-24 (1996); Massachusetts Electric Company, D.P.U. 95-40, at 7-8 (1995); D.P.U. 93-60, at 25-26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993). In addition, the Department has stated that:

> In reviewing the investments in main extensions that were made without a cost benefit analysis, the [c]ompany has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The [c]ompany must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

ii. Introduction

The Company reported a total of $1,189,550,457 in rate base additions and $93,788,658 in cost of removal for a combined capital investment total of $1,283,329,114 from January 1, 2009 through June 30, 2015 (Exhs. NG-JHP-1, at 5; DPU-7-23, Att. (Supp.)). National Grid reported 1,257 specific projects for $509,652,488; 62 blanket projects for $463,986,528; and 99 program projects for $217,111,440 (Exh. DPU-7-23 Att. (Supp.); RR-DPU-12). The Company then reduced its total plant additions by $1,200,000 to correct an error found in the D.P.U. 11-18 audit to arrive at the total investment of $1,189,550,457 (Exhs. NG-JHP-1, at 12; DPU-7-23, Att. (Supp.); RR-DPU-12)). We find that this correction is appropriate.

iii. Capital Authorization Policies

As noted above, National Grid groups its capital projects into three categories: (1) specific projects; (2) blanket projects; and (3) program (or other annual) projects (Exh. NG-JHP-4, at 1). A specific project is approved for the total cost of a defined body of work and will be closed once the work is complete (Exh. NG-JHP-4, at 1; RR-DPU-43, Att. 2, at 9).

In other words, specific projects are set up to perform a specifically identified scope of work that can span multiple years and can contain one or many work orders at any given time (Exh. NG-JHP-4, at 1, 8, 12). A blanket project is set up to collect high volume, smaller dollar work orders within a certain budget classification (Exh. NG-JHP-4, at 8; RR-DPU-43, Att. 2, at 8). A program project contains work orders for similar types of construction following a specific strategy (e.g., recloser installations) (Exh. NG-JHP-4, at 12; RR-DPU-43, Att. 2, at 9). Blanket and program projects are budgeted and approved annually (Exh. NG-JHP-4, at 12). Other annually-approved projects, such as storm-related projects, are categorized as "program" projects in order to indicate that they are not blanket projects (Exh. NG-JHP-4, at 12).

The Company maintains a written DOA policy,[77] and written sanctioning procedures,[78] for specific, blanket, and program projects (RR-DPU-43 and Atts. 1-3). A DOA is an authorization to enter into contracts, other external commitments, or to take (or not) other actions that might result in an obligation by National Grid (RR-DPU-43, Att. 2, at 8). A DOA is obtained at the funding project level (RR-DPU-43, Att. 2, at 8). Re-sanctioning is the process of receiving authorization to revise the existing approved cost, scope, or schedule (RR-DPU-43, Att. 2, at 8). The Company's capital authorization policies and procedures differ for projects

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77 The Company has not made any material changes to its DOA policy since 2009 (RR-DPU-43).

78 Prior to May 2011, the Company's capital authorization process consisted of department-specific sanction committees, with separate processes and sanctioning templates (RR-DPU-43). On May 31, 2011, the Company began using the USSC for all utility services using a common template and single sanction procedure (RR-DPU-43). The USSC originally reviewed and approved all projects with estimated spending at or above $1 million (RR-DPU-43). In 2013, the Company's capital authorization policy was revised to focus the USSC's review and approval on projects greater than $8 million and to create a subcommittee responsible for reviewing and approving projects greater than $1 million, but at or less than $8 million (RR-DPU-43).

with expected costs of less than $1 million and for projects with expected costs at or above $1 million (RR-DPU-43 and Atts. 1-3).

(A) Projects Under $1 Million

The requested DOA specific projects with costs under $1 million constitute the gross expected expenditure (i.e., the Company does not subtract from the DOA amounts for anticipated contributions in aid of construction ("CIAC") or other contributions) (RR-DPU-43, Att. 2, at 4). The DOA for a specific funding project is revised prior to exceeding the approved DOA (RR-DPU-43, Att. 2, at 4).[79] Specific funding projects must be re-sanctioned as soon as the actual cost is, or is forecasted to be, ten percent above the authorized expenditure or $25,000, whichever is greater (RR-DPU-43, Att. 2, at 6).[80]

The responsible person must provide written justification for the re-sanctioning along with the new requested DOA amount for the funding project using a "Change in DOA Request Form" (RR-DPU-43, Att. 2, at 7). The higher the total cost of the funding project, the greater the level of detail is required in the documentation to properly justify the funding project re-sanction (RR-DPU-43, Att. 2, at 7). The justification must be clear, concise and accurate and should contain enough information to allow a full understanding of the reasons for the increase (RR-DPU-43, Att. 2, at 7). Once approval is obtained, the funding project DOA in the

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79 In the event a funding project is originally estimated to be under $1 million but the forecasted or actual costs exceed $1 million, the funding project must be re-sanctioned pursuant to the policies applicable to projects with costs over $1 million, as described below (RR-DPU-43, Att. 2, at 6).

80 For all three types of projects the responsible individual must obtain re-sanction of all funding projects that exceed their authorized spending limit on a timely basis, but in no case later than 60 days after being notified that the project has exceeded the authorized spending limit (RR-DPU-43, Att. 2, at 6).

Company's computer system will be updated (RR-DPU-43, Att. 2, at 7). Specific projects may be grouped with other related specific projects and the Company considers these groups of projects at the aggregate level when determining whether the project is over budget (Tr. 3, at 426).

Blanket and program funding projects under $1 million are sanctioned at the start of each fiscal year to reflect the upcoming budget and routed for DOA approval (RR-DPU-43, Att. 2, at 5). Blanket work orders are linked to blanket funding projects and must not exceed $100,000 (RR-DPU-43, Att. 2, at 5). The DOA requested for blanket and program funding projects constitutes the gross expected expenditure (i.e., the Company does not subtract amounts for anticipated CIAC or other contributions) (RR-DPU-43, Att. 2, at 5). Blanket and program projects under $1 million are monitored on a monthly basis and revised with explanations within 60 days of the end of the fiscal year (RR-DPU-43, Att. 2, at 6). Blanket projects require a USSC closure paper[81] (RR-DPU-43, Att. 2, at 6).[82] Programs of less than $1 million require change in DOA forms, but do not require closure papers (Exh. NG-JHP-4, at 13; Tr. 3, at 431-432). Additionally, program projects under $100,000 do not require change in DOA forms or closure papers (Tr. 3, at 430-432).

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[81] A closure paper is prepared at the completion of a funding project that details the financial and objective outcomes of the funding project (RR-DPU-43, Att. 3, at 13).

[82] We note that there appears to be an inconsistency in the Company's re-sanctioning procedures and other documentation with respect to whether closure papers are completed for program projects under $1 million (Compare RR-DPU-43, Att. 2, at 6 with Exh. NG-JHP-4, at 13). Based on other documentation in the record and the Company's testimony, it appears that the Company's policy is to not require a closure paper for program projects under $1 million (see, e.g., Exhs. NG-JHP-3(f), JHP-2, at 13; NG-JHP-4, at 13; Tr. 3, at 431-432). As noted below, the Department directs the Company to clarify the capital authorization policies on this point.

Additionally, capital funding project overrun reports are produced on a monthly basis (RR-DPU-43, Att. 2, at 7). These reports identify funding projects that have exceeded or are forecasted to exceed the authorized DOA basis (RR-DPU-43, Att. 2, at 7). Within ten business days, the responsible personnel must prepare a written plan to bring the affected funding project within DOA limits (RR-DPU-43, Att. 2, at 7).

For the Company's annual capital investment report filing, the Company prepares variance analysis reports for blanket and program funding projects on a fiscal-year basis (see, e.g., Exh. NG-JHP-4, at 18; Tr. 3, at 431-431). For purposes of providing variance explanations, the Company groups related blanket projects together and related program projects together (Tr. 3, at 431-431).

(B) Project Costs at or above $1 Million

For all types of projects at or above $1 million a sanction paper is used to approve the expenditure (RR-DPU-43, Att. 3, at 5). A sanction paper is the document submitted to the USSC for project approval and is considered the final approval to undertake the funding project (RR-DPU-43, Att. 3, at 16). A sanction, as opposed to a partial sanction, is generally prepared for the full scope and cost of the funding project (RR-DPU-43, Att. 3, at 16). Generally the costs are expected to have a variance tolerance of plus or minus ten percent (RR-DPU-43, Att. 3, at 16). The funding project amount to be sanctioned, and for which a DOA is requested, shall be the gross expected expenditure (i.e., the Company does not subtract amounts for anticipated CIAC or other contributions) (RR-DPU-43, Att. 3, at 5). Closure papers are required for all funding projects of $1 million or greater (RR-DPU-43, Att. 3, at 9).

A specific funding project of over $1 million must be re-sanctioned within 60 days of notification that the cost is forecasted to vary outside of the tolerance approved in the project sanction paper (RR-DPU-43, Att. 3, at 8). Re-sanction papers should not re-state the original need, but must include a detailed explanation of the new sanction requirements and why they have changed from those that were originally approved (RR-DPU-43, Att. 3, at 9). In addition, the re-sanction paper should include details of lessons learned including an explanation of any significant variances in cost (RR-DPU-43, Att. 3, at 9). If the lessons learned and explanations are not fully known at the time, they must be included in the closure paper (RR-DPU-43, Att. 3, at 9). Specific funding project closure papers shall be completed as soon as possible after all work orders and projects are closed (RR-DPU-43, Att. 3, at 9). Related specific funding projects shall be included in one investment document (RR-DPU-43, Att. 3, at 10). A funding project is related to another funding project if it cannot fully accomplish its intended purpose unless the other funding project is also carried out (RR-DPU-43, Att. 3, at 10). These related funding projects should be identified in a sanction paper (RR-DPU-43, Att. 3, at 11). The Company considers these groups of projects at the aggregate level when determining whether the project is over budget (Tr. 3, at 426).

Blanket and program funding projects at or above $1 million are approved for each fiscal year (RR-DPU-43, Att. 3, at 8). Blanket and program funding projects may not be segmented into smaller pieces in order to sanction the spending at a lower level of authority than would otherwise be required (RR-DPU-43, Att. 3, at 8). For blanket projects, a closure document is presented at the end of each fiscal year (Exh. NG-JHP-4, at 18, 2; RR-DPU-43, Att. 3, at 8). For program projects, a closure document is presented at the end of each fiscal year unless otherwise

specified in the strategy or sanction paper (Exh. NG-JHP-4, at 18, 2; RR-DPU-43, Att. 3, at 8). Program funding project closure papers shall be completed as soon as possible after all work orders and projects are closed (RR-DPU-43, Att. 3, at 9).

For the Company's annual CapEx filing, the Company prepares variance analysis reports for blanket and program funding projects on a fiscal-year basis (see, e.g., Exh. NG-JHP-4, at 18; Tr. 3 at 431-431). For purposes of providing variance explanations, the Company groups related blanket projects together and related program projects together (Tr. 3, at 431-431).

iv. Project Documentation

The Company provided project documentation at various points in this proceeding. As part of its initial filing, the Company provided the filings made in each of the previous CapEx filings, as well as documentation relating to capital investments made during the first six months of 2015 (Exhs. NG-JHP-3; NG-JHP-4). As noted above in Section VII.B.3, the Company provided, with its initial filing, various forms of documentation for specific projects over $50,000 and all blanket and program projects including: (1) a project summary sheet that includes project number, project descriptions, approved amount, total to date project spending, project status, approval history, and in-service additions and cost of removal figures; (2) a project approval report; (3) sanction papers; (4) a retirement report; (5) a direct/indirect summary report; (6) a work order asset addition report; (7) a project cost summary (see, e.g., Exhs. NG-JHP-3; NG-JHP-4). The Company also provided closure papers for some specific projects (see, e.g., Exhs. NG-JHP-3; NG-JHP-4). For blanket and program projects, the Company also

provided a fiscal year variance analysis report and a fiscal year closure paper (Exh. NG-JHP-4, at 12, 13).[83]

Over the course of the proceeding, the Company provided additional documentation including a variance explanation for a specific project, closure papers for 26 specific projects, closure papers for five specific projects and eight program projects (Exhs. DPU-17-23; AG-21-1, Atts. 1, 2; NG-JHP-Rebuttal-2, at 18-20). Additionally, on May 3, 2016, the Company provided closure papers for 22 blanket projects (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)). Further, as noted above in Section VII.B.5.a.i, on June 2, 2016, the Company provided reauthorization documents and closure papers for certain program projects placed in service in FYs 2013, 2014, and 2015, which the Department has excluded from the evidentiary record as provided in Section VII.5.a.iii above (Exh. NG-JHP-Rebuttal-2 (Supp.)). On that date, the Company also provided a supplemental response to information request DPU-7-23, showing the Company's specific projects that are combined into a larger group of projects (Exh. DPU-7-23, Att. (Supp.)). As discussed below, the Attorney General challenges the sufficiency of the documentation provided for 20 specific projects, 32 blanket projects, 47 program projects, and two storm program projects (Attorney General Brief at 12-19).

The Department finds that a project cost document production threshold of $50,000 for specific projects is appropriate for a company the size of National Grid. See D.P.U. 14-150,

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83 The Company initially did not provide closure papers for 31 specific projects, but provided them through discovery. Nor did it initially provide blanket project closure papers for fiscal years 2013 and 2014, which were provided at the beginning of hearings. Also, the Company initially did not provide closure papers for seven program projects over $1 million and reauthorization forms for 14 program projects over $100,000, but they were provided after the close of hearings and have been excluded from the record above.

at 58; New England Gas Company, D.P.U. 11-42, at 3 n.4 (2013); D.P.U. 10-114, at 81, n.67. Nevertheless, document production thresholds used by the Department in the discovery process do not mean that projects of a lower value are exempt from scrutiny or the requirement that a company maintain adequate documentation to support the prudence of these capital additions. D.P.U. 14-150, at 58. Rather, the Department and intervenors may inquire into any project regardless of its final cost. D.P.U. 14-150, at 58; D.P.U. 12-25, at 77; D.P.U. 10-55, at 188.

v. Specific Projects

The Company seeks inclusion of $509,652,488 in investments for 1,253 specific projects, including the cost of removal (Exh. DPU-7-23, Att. (Supp.); RR-DPU-12). There were 772 specific projects with in-service additions greater than $50,000 between January 1, 2009 and June 30, 2015 (Exh. DPU-10-12 (Att.)). Of those specific projects, 360 had variances in excess of ten percent (Exh. DPU-10-12 (Att.)). The Attorney General recommends that the Department exclude 20 of these projects from rate base because the Company did not provide a variance explanation (Attorney General Brief at 11-12).

We first consider the 752 uncontested specific projects. The Department has reviewed the information supporting the Company's completed projects, including all supporting documents described above (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 and Atts. 1-3; DPU-17-23; AG-21-1, Atts. 1, 2). Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of the Company's uncontested specific projects in rate base. We now turn to the 20 contested specific projects.

A company is required to provide a reasonable explanation for cost variances, based on the specifics of each project, sufficient for the Department to evaluate the reasonableness and prudence of any cost variance. D.P.U. 14-150, at 50; D.P.U. 13-75, at 95, 105; D.P.U. 12-25, at 79-80, 82; D.P.U. 10-114, at 85-87; D.P.U. 10-55, at 179-180. If a company adequately justifies the reasons for any cost variance, the Department will consider the costs of the project eligible for inclusion in rate base. D.P.U. 14-150, at 50. If, however, a company is unable to justify the reasons for a cost variance, the Department will exclude the excess costs to the extent that the Company has not met its burden of proof. D.P.U. 14-150, at 50-51; D.P.U. 13-75, at 114; D.T.E. 03-40, at 68; D.P.U. 95-118, at 49-55. The Department has directed companies to address the cost variances for capital expenditures between the amount approved for projects and the actual amount required to complete the projects. D.P.U. 10-79, at 7. The Department has approved a company's use of authorized amounts that are refined over time for purposes of conducting a variance analysis because they are more reflective of the costs to be incurred by the Company in undertaking the approved project. D.P.U. 15-80/D.P.U. 15-81, at 75.

The Department requested an explanation for the variance on 23 specific projects (Exhs. DPU-17-1 through DPU-17-23). For 20 of these projects, the Company responded that the projects were part of a larger group of related projects that in the aggregate did not exceed the ten percent tolerance and, therefore, the Company did not perform a variance investigation (see, e.g., Exh. DPU-17-3). Based on the Company's internal policies, it groups related projects and considers these groups at the aggregate level when applying the threshold required for a variance explanation (see, e.g., Exh. DPU-17-3; Tr. 3, at 426-427). The Department finds that the Company's grouping practice is a sufficient project management tool for reviewing cost

control for the ratemaking treatment of plant additions. Therefore, the Department will not require variance analyses for specific projects within the groupings. In future filings involving plant additions, i.e., base rate case, CIRM filing, the Department will continue to review the Company's project management tools to ensure that there adequate cost control measures.

In any event, the Company stated that reauthorization documents adequately explain the reasons for a reauthorization at the specific project level (Tr. 3, at 425-429). With the documentation provided in the instant case, the Department will review the capital project documentation and closing reports for all specific projects that are part of a group of related projects to determine whether the expenditures are prudently incurred.

The Department has reviewed the documentation the Company provided for these 20 specific projects,[84] including all supporting documents (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; JHP-Rebuttal-2; DPU-17-23; AG-21-1, Atts. 1,2). For the 20 specific projects, the Company provided various forms of documentation including, but not limited to, project summary sheets, project approval reports, authorization documents, retirement reports, asset addition reports, project cost summary reports, and closure papers.[85] The closure papers or re-sanction papers contain reasons for the reauthorization requests during the lifecycle of the project.[86] To the

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84 The 20 specific projects are: C008666; C005339; C014549; C023591; C036385; C028886; C002364; C002388; C012018; C012502; C024120; C005342; CD01253; C001423; C028871; C029104; C031552; CD01174; C031324; and C002504.

85 The Company did not provide a closure paper for Project C008666, stating that the current sanction process did not exist at the time the project was progressing (Company Reply Brief at 17).

86 Exhs. NG-JHP-Rebuttal-2 at 13, 28, 39 44, 50, 57; NG-JHP-3(b), JLG-6 at SPCFC-1275; NG-JHP-3(c), JLG-6 at SPFC-1231, 1369; NG-JHP-3(d), JLG-6, at SPFC-6, 1112-1116; NG-JHP-3(f), JHP-6, at SPFC 1270-71, 2328; NG-JHP-4, at SPFC-357.

extent that these projects had a variance between the final approved amount and the actual spent amount,[87] that variance was less than ten percent and, therefore, would not trigger a separate variance explanation under the Company's policies (see, e.g., Exh. DPU-17-3; Tr. 3, at 392, 398, 426-427).

The explanations provided for the variances and reauthorizations during the lifecycle of the projects include unforeseen environmental issues, increases in project scope, revisions to design, increase in materials and labor costs, low estimates, project initially only given a partial sanction for preliminary engineering, and various other project-specific issues.[88] While most of these explanations were provided at the group level, not the individual project level, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of these 20 projects in rate base.

vi. Storm Capital Programs

The Company reported storm capital programs using five project numbers: C014821, C014822 C21594, C02216, and C22217. The Attorney General specifically challenges the sufficiency of the variance explanations for two storm program projects for fiscal year 2010,

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87 We have approved a company's use of authorized amounts that are refined over time for purposes of conducting a variance analysis because they are more reflective of the costs to be incurred by the Company in undertaking the approved project. D.P.U. 15-80/D.P.U. 15-81, at 75.

88 See, e.g., Exhs. NG-JHP-Rebuttal-2 at 13, 28, 39 44, 50, 57; NG-JHP-3(a), JLG-6, at SPFC-1624; NG-JHP-3(c), JLG-6, at SPFC-1231, 1369; NG-JHP-3(d), JLG-6, at SPFC-6, 1112-1116; NG-JHP-3(e), JLG-6, at SPFC-3446; NG-JHP-3(f), JHP-6, at SPFC-1270-71; NG-JHP-4, at SPFC-357, 525.

projects C014821 and C014822, totaling a $ 2.4 million variance; and one fiscal year 2012 project, C014821, with a $9.3 million variance (Attorney General Brief at 20). Additionally, the Attorney General, as part of her challenge of program projects discussed below, contests the sufficiency of the documentation for storm programs C014821, C21594, C02216, and C22217, which span FYs 2013 through 2015.[89]

The Company provided closure papers and variance analysis reports with its initial filing for the two fiscal year 2010 projects and provided a closure paper containing a variance explanation for the fiscal year 2012 project (Exhs. NG-JHP-3(b), JLG-8, at PRGM-0329, 341; NG-JHP-3(d), JLG-8, at PRGM-163; DPU-19-1; DPU-19-2). The variance explanation for the fiscal year 2010 projects states that storm restoration programs are approved annually based on historic trends and that the cost of mandatory storm restoration activities are strictly dependent on size/scale of storms incurred during the year (Exh. NG-JHP-3(b), JLG-8, at PRGM-0329, 341). The variance explanation provided by the Company for the fiscal year 2012 project states that three major storms resulted in significant damage across the state's infrastructure (Exhs NG-JHP-3(d), JLG-8, at PRGM-163; DPU-19-40).[90] The Company also explained that in reporting the costs to the Department, the Company mistakenly used the budgeted amounts for the fiscal year and not the final authorized amount from the closure papers, and that if the correct amount had been used, the variance would be minimal (Exhs. DPU-19-1; DPU-19-2; DPU-19-40; see also Exh. DPU-7-23, Att. (Rev.)).

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89 We address the fiscal year 2013-2015 storm programs in the section below.

90 The storms were a tornado in June 2011; Tropical Storm Irene in August 2011; and a major snowstorm in October 2011 (Exh. DPU-32-4).

We find that the variance explanations provided are sufficient for purposes of storm program projects. The Company establishes budgets for storm program projects based on multi-year historic trends (Exh. NG-JHP-1, at 19). The work performed to restore service is inherently unplanned and not fully quantifiable until after the work has been performed (Exh. NG-JHP-1, at 19). Therefore, we will not exclude these projects from rate base on this basis.

Further, we note that the Department imposed substantial fines on National Grid after determining that restoration efforts related to two storms were inadequate, in part, because the Company mobilized insufficient resources. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. However, in this instance, we find that the Department's imposition of those fines does not automatically warrant a disallowance of the costs that the Company incurred in responding to these storms. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. The Department did not make a finding that any of the costs the Company incurred in responding to the storm were imprudent under the standard of review for plant additions. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41. Instead, we stated that if the Company seeks recovery of storm costs in a future Department proceeding, the Department will determine whether the Company's storm expenses were prudently incurred in that proceeding and whether or not to deny any of the Company's storm related expenses. D.P.U. 11-85-A/D.P.U. 11-119-A at 39-41, citing Fitchburg Gas and Electric Light Company, D.P.U. 09-01-A at 195 (2009); D.P.U. 93-60, at 24. Based on our findings above, we conclude that the costs for these storm capital programs projects were prudently incurred and that the capital investments are used and useful.

vii. Blanket & Program Projects

The Company seeks inclusion of $217,111,440 in investment for 99 program projects and $463,986,528 for 62 blanket projects (Exh. DPU-7-23, Att. (Supp.); RR-DPU-12).[91] As noted above, for blanket projects, the Company provided project documentation consisting of: (1) fiscal year blanket project summary sheets; (2) project cost summaries; (3) fiscal year approval documents; (4) fiscal year summary project variance analyses[92] and closure papers;[93] (5) calendar year work order asset detail reports; (6) calendar year retirement reports; and (7) direct/indirect summary reports (see, e.g., Exhs. NG-JHP-3; NG-JHP-4, at 10-13). In its initial filing, the Company did not provide closure papers for 31 blanket projects for FYs 2013 and 2014;[94] the Company filed them on May 3, 2016 (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)).

For program projects, the Company provided project documentation consisting of: (1) fiscal year program project summary sheets; (2) project cost summaries; (3) fiscal year

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91 The Company's programs and blanket projects are often reauthorized for the next fiscal year using the same project number. There are 99 unique program project numbers and 62 unique blanket project numbers, many of which repeat from year to year (Exh. DPU-7-23, Att. (Rev.)).

92 See, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803.

93 See, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-126-149; NG-JHP-3(c), JLG-7, at LNK-123-129; NG-JHP-3(f), JHP-7, at BLNK-101-110; NG-JHP-4, at 92).

94 These projects include: CBN0002; CBN0004; CBN0010; CBN0011; CBN0012; CBN0014; CBN0015; CBN0016; CBN0017; CBN0022; CBS0010; CBS0011; CBS0014; CBS0020; CBS0022; CBW0002; CBW0006; CBW0010; CBW0011; CBW0014; CBW0016; CBW0020; CN00420; CNM0002; CNM0004; CNM0010; CNM0011; CNM0014; CNM0017; CNM0020; and CNM0022.

approval documents; (4) fiscal year summary project variance analyses[95] and closure papers;[96] (5) calendar year work order asset detail reports; (6) calendar year retirement reports; and (7) direct/indirect summary reports (Exhs. NG-JHP-3; NG-JHP-4, at 10-13). The Company initially did not file closure papers for seven program projects of over $1 million;[97] it filed six of them on June 2, 2016 (Exh. NG-JHP-Rebuttal-2 (Supp.)). The Company did not initially file reauthorization paperwork for 14 program projects over $100,000 and less than $1 million, but filed them on June 2, 2016 (Exh. NG-JHP-Rebuttal-2 (Supp.)).[98]

As noted above, the Attorney General argues that the Company's submission of closure papers on May 3, 2016, for 31 blanket projects was untimely and recommends disallowance of $19.6 million dollars associated with these projects. The Attorney General challenges 47 program projects arguing that closure papers,[99] if any, were filed on June 2, 2016, and

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95 Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157.

96 Exhs. NG-JHP-3(b), JLG-8, at PRGM-331-343; NG-JHP-3(c), JLG-8, at PGRM-262-269; NG-JHP-3(d), JLG-8, at PGRM-156-168). Under the Company's capital authorization policies, program projects of less than $1 million do not require closure papers (Exh. NG-JHP-4, at 13).

97 On June 2, 2016, the Company filed closure papers for the following projects: C005490; C005500; C014821; C021594; C022216; and C022217. The Company did not file a closure paper for C006138.

98 On June 2, 2016, the Company filed Change in DOA forms for the following projects: C005543; C005469; C028147; C025810; C032270; CD00017; C025619; C025813; C027898; C031398; C031774; C035584; C049352; and CD01258.

99 The Attorney General argues that 47 program projects should be disallowed because, if closure papers were filed at all, they were filed after the close of the evidentiary hearings (Attorney General Brief at 16). We note that for 21 of the Attorney General's challenged projects, the Company filed closure papers (or other documentation) on June 2, 2016.

recommends disallowance of $18.2 million associated with these projects. The Attorney General, therefore, recommends disallowance of $ 37.8 million in blanket and program costs based on the lack of timeliness of filing the Company's closure papers.

(A) Blanket Projects

The Attorney General contests 31 of the Company's 62 blanket projects. We first consider the 31 uncontested blanket projects.[100] The Department has reviewed the information supporting the Company's 31 uncontested blanket projects including all supporting documents described above, with specific attention to the variance analyses (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to, increased residential applications for new business, increased applications for new attachments, increased levels of work relating to damage failures, increased equipment purchases, and various other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803). While these explanations were provided for a group of similar blanket projects, not the individual blanket projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

For the remaining 26 projects, the Company did not file any closure papers or documentation on June 2, 2016 (Company Brief at Appendix 1, Table 2).

100 The uncontested blanket projects are: CBN0009; CBN0013; CBS0002; CBS0004; CBS0006; CBS0009; CBS0012; CBS0013; CBS0015; CBS0016; CBS0017; CBS0025; CBW0004; CBW0009; CBW0012; CBW0013; CBW0015; CBW0017; CBW0022; CBW0070; CN00404; CN00504; CN00520; CNM0006; CNM0009; CNM0012; CNM0013; CNM0015; CNM0016; CNM0070; and CBW0025.

We now turn to the 31 contested blanket projects. The Company did not provide the FYs 2013 and 2014 blanket closing reports with its initial filing or during the discovery period. The Company did, however, provide closure papers for all of these projects on May 3, 2016 as a supplement to information requests propounded by the Department (Exhs. DPU-20-31 (Supp.); DPU-20-35 (Supp.)). We share the Attorney General's concern that the Company was unable to provide these closure papers with its initial filing. Pursuant to the Company's capital authorization policies, these closure papers should have been completed at the close of FYs 2013 and 2014 and available at the time the Company filed its petition in this case (see RR-DPU-43 & Atts. 1-3). We find, however, that the filing of these closure papers was not so late as to prevent the Department and the parties enough time to conduct an adequate review of their contents. In a base rate proceeding, it is not unusual for a petitioner to provide documents and information during the course of hearings that it has not previously provided in the initial filing. Indeed, parties are under a continuing obligation to supplement discovery responses throughout the course of a proceeding. D.P.U. 12-25, at 106-107, citing 220 C.M.R. § 1.06(6)(c)(5); D.P.U. 09-30, at 174; D.P.U. 08-27-B at 22; D.T.E. 02-24/25, at 32-33; D.P.U. 88-123-B at 57-58.

The Department is not persuaded that the Attorney General was prejudiced by the production of these documents on May 3, 2016, which was the second day of hearings and before the record closed. Further, although the documents were produced the day before the Company's witness was to testify, the witness appeared on two consecutive days. Additionally, the Department reserved several days at the end of the evidentiary hearings for additional cross examination, so the Attorney General could have recalled the witness at that time. Moreover, the

Company's production constituted two ten-page documents, one for each fiscal year. The documents were not so voluminous as to prevent the Attorney General from reviewing them during the course of the evidentiary hearings to at least determine if she needed the Company's witness to appear again. Instead, the Attorney General concluded her questioning of the witness on May 5, 2016, two days after the documents were filed, and never asked that the witness be made available for further questioning on this or any other subject (Tr. 3, at 457).

More importantly, the closure papers provided by the Company on May 3, 2016, were largely duplicative of the project documentation already provided as part of the Company's initial filing (Exhs. NG-JHP-3(d), NG-JHP-3(e), JLG-7; NG-JHP-3(f), JHP-7). Specifically, the cost information contained in the closure papers is the same as the cost information in the project summaries and project cost summaries (Exhs. NG-JHP-3(d), NG-JHP-3(e), JLG-7; NG-JHP-3(f), JHP-7). Similarly, the variance analyses contained in the closure papers are the same as the variance analyses in the 2013 and 2014 blanket variance analysis reports (Exhs. NG-JHP-3(e), JLG-7, at BLNK-3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803).

Based on these considerations, we find that a reasonable examination of the documents produced on May 3, 2016, was feasible given the number, length and nature of the documents, and the timing of their production vis-à-vis the evidentiary hearing schedule. Therefore, the Department will not exclude these projects from rate base due to the timing of the project documentation. We do, however, expect that National Grid will abide by its own capital authorization policies (i.e., preparing closure papers at the close of the fiscal year) as a reasonable means of maintaining adequate cost controls. Specifically, we note that the closure paper is the opportunity for the Company to reflect upon and document the lessons learned and

to ensure that the Company has performed all close out activities (Exhs. DPU-20-31, at 3 (Supp.); DPU-20-35, at 3 (Supp.)). Given that the Company ultimately did provide sufficient cost information and variance analyses for the projects at issue, we find that the Company's failure to timely compile the closure papers (including documentation of lessons learned) is insufficient to support a finding that the Company failed to maintain adequate cost controls.

The Department has reviewed the information supporting the 31 contested blanket projects including all supporting documents described above, with specific attention to the variance analyses (see, e.g., Exhs. NG-JHP-3; DPU-20-1 through DPU-20-53; DPU-20-31 (Supp.); DPU-20-35 (Supp.); RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to, increased residential applications for new business, increased applications for new attachments, increased levels of work relating to damage failures, increased equipment purchases, and various other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-7, at BLNK-122-125; NG-JHP-3(c), JLG-7, at BLNK-119-122; NG-JHP-3(e), JLG-7, at 3156-3161; NG-JHP-3(f), JHP-7, at BLNK-2799-2803). While these explanations were provided for a group of similar blanket projects and not the individual blanket projects, we nevertheless find them sufficient under the Company's current policies to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful. Accordingly, the Department will include the cost of the Company's blanket projects in rate base.

(B) Programs

As noted above, the Attorney General challenges 47 total program projects arguing that closure papers, if filed at all, were filed after the close of evidentiary hearings. We first consider the 51 uncontested program projects.[101] The Department has reviewed the information supporting the Company's 51 uncontested program projects including all supporting documents described above, with specific attention to the variance explanations[102] and closing reports[103] (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The Company provided reasons for variances including, but not limited to: increase in cost of transformers, carryover work from prior years due to weather or outages, incompatibility of parts purchased from different vendors, change in scope or strategy after initial budget was set, and other project-specific reasons (see, e.g., Exhs. NG-JHP-3(b), JLG-8, at PRGM-0323-0330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157). While these explanations were provided for a group of similar program projects, not the individual program projects, we

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101 The uncontested program projects are: C004494; C005495; C005499; C007266; C005543; C005442; C005446; C005447; C005451; C005453; C030604; C026264; C026279; C026280; C005509; C005514; C005519; C024499; C005558; C005826; C006629; C014322; C014323; C014324; C025239; C025899; C027002; C008407; C008414; C008511; C016123; C017453; C023512; C036906; C001379; C025320; C025683; C026056; C031397; C031778; C031831; C023491; C032027; C032570; C026761; C026836; C039984; C017892; C029780; C037962; and CAP0004.

102 The Company provided variance explanations for fiscal years 2010 through 2015 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157).

103 The Company provided closing reports with its initial filing for fiscal years 2010, 2011, and 2012 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-331-343; NG-JHP-3(c), JLG-8, at PGRM-262-269; NG-JHP-3(d), JLG-8, at PGRM-156-168).

find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

With respect to the 47 contested projects, the Attorney General argues that closure papers, if filed at all, were filed late on June 2, 2016, after the close of evidentiary hearings. First, we find that for 26 of the program projects the Company did not provide any documentation on June 2, 2016,[104] but did provide documentation with the initial filing as described above. The Department has reviewed the information supporting these 26 program projects including all supporting documents with specific attention to the variance explanations (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43, Atts. 1-3).[105] The Department notes that the program projects are less than $100,000, and under the Company's capital authorization policies do not require variance analyses or closure papers (Tr. 3, at 430-432). Thus, we will not exclude these projects from rate base based on the fact that the Company did not submit closure papers. We further note, however, that the Company did provide some variance analyses, which include cost overruns due to carryover work from prior years caused by severe weather events or outages, additional work written to train workers, and changes in project scope (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274;

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104 These consist of projects: C005432; C005563; C006642; C005439; C005441; C005444; C005449; C016492; C005475; C005480; C059664; C032015; C032016; C032018; C033822; C032272; C016120; C016121; C018594; CD00259; C025326; C027927; C032024; C032572; C033764; and C033765.

105 The Company provided variance explanations for fiscal years 2010 through 2015 (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157).

NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8, at PGRM-1149-1157). While these explanations were provided for a group of similar program projects, not the individual program projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

We now turn to the 21 program projects for which the Company filed documentation on June 2, 2016.[106] As discussed above in Section VII.5.a.iii, the Department has granted the Attorney General's motion to strike these documents from the record. Therefore, we will evaluate each of these program projects based on information regarding these projects that was in the record prior to the close of hearings (Exhs. NG-JHP-3; NG-JHP-4).

The Department has reviewed the information supporting the Company's 21 program projects, as described above, with specific attention to the variance explanations (see, e.g., Exhs. NG-JHP-3; NG-JHP-4; RR-DPU-43 & Atts.). The reasons for the variances include carryover work from prior years due to severe weather events or outages, additional work written to train workers, and changes in project scope (Exhs. NG-JHP-3(b), JLG-8, at PRGM-323-330; NG-JHP-3(c), JLG-8, at PGRM-270-274; NG-JHP-3(d), JLG-8, at PGRM-160-168; NG-JHP-3(e), JLG-8, at PGRM-1184-1191; NG-JHP-3(f), JHP-8,

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106 These consists of projects: C005490; C005500; C014821; C021594; C022216; C022217; C005543; C005469; C028147; C025810; C032270; CD00017; C025619; C025813; C027898; C031398; C031774; C035584; C049352; and CD01258. Included in this number is one program project, C006138, for which the Company indicated it would be submitting a closure paper, but did not submit one with the June 2, 2016, filing. As explained below, however, we find that there is sufficient information in the record to evaluate the prudency of this project despite the absence of the closure paper.

at PGRM-1149-1157). The variance explanations for the 2013, 2014, and 2015 storm programs state that storm restoration programs are approved annually based on historic trends, that storm restoration work is mandatory, and that charges and adjustments from FY 2013 events such as Hurricane Sandy and the February Nemo storm were paid in FY 2014 (Exhs. NG-JHP-3(e), JLG-8, at PGRM-1190; NG-JHP-3(f), JHP-8, at PGRM-1155).

While these explanations were provided for a group of similar program projects, not the individual program projects, we find them sufficient, under the Company's current policies, to allow a determination of prudence. Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful.

Additionally, as we stated above, we expect that National Grid will abide by its own capital authorization policies (i.e. preparing closure papers and reauthorization forms) as a reasonable means of maintaining adequate cost controls. Specifically, we note that the closure paper is the opportunity for the Company to reflect upon and document the lessons learned and ensure all close out activities have been performed (Exh. NG-JHP-1, at 17). However, given that National Grid did provide sufficient cost information and variance analyses for the projects at issue, we find that the Company's failure to timely compile and timely produce the closure papers is insufficient to support a finding that the Company failed to maintain adequate cost controls.

viii. Filing Requirements

The Company shall provide, as part of its next CIRM filing the following: (1) prefiled testimony; (2) for capital projects placed in service costing more than $50,000, project details

including: project summary sheet, project cost summary, approval documents such as sanction/authorization papers and re-sanction/reauthorization documents, as required by the Company's capital authorization policies, work order asset detail reports, retirement reports, and direct/indirect reports; (3) closure papers, as required by the Company's capital authorization policies; (4) variance analyses for all projects over $50,000 consistent with the Company's capital authorization policies; (5) fiscal year variance analysis reports for its blanket and program projects; (6) a list of cancelled projects and a description of the disposition of the associated charges; and (7) new policies or updates to policies since the previous CIRM filing, affecting the Company's methods of: (i) approving delegations of authority, sanctioning and re-sanctioning funding projects, (ii) charging capital versus expense, (iii) determining when a capital asset is in danger of failure and should be replaced as part of a damage/failure blanket capital authorization, and (iv) instituting any other changes in accounting, allocation, and/or operational matters.

In its next CIRM filing, the Company also shall explain the cost variances between the final amount approved and the actual amount required to complete the project. For blanket and program projects that are not reauthorized throughout the year, the Company shall explain cost variances between the initial budgeted amount and the actual amount required to complete the project. Further, the Company shall provide fiscal year-end variance reports for blanket and program projects for the fiscal year ending in the calendar year under review and the fiscal year following the calendar year under review. The Company shall also describe any cost control efforts it has undertaken in response to the variances.

Additionally, the Department notes some inconsistencies with respect to when the Company requires reauthorization documentation, closure papers, and variance analyses. In

order to review capital project documentation and understand the Company's complex capital project authorization process and blanket authorization policy, a significant amount of time during evidentiary hearings was devoted to exploring when closure papers and variance explanations are required (see Tr. 3, generally). Going forward, the Department directs the Company to provide all of its capital project documents in text searchable format with its CIRM filings. Moreover, the Department directs the Company to use consistent terminology, to the extent possible, and to ensure that policies are described consistently across documents (e.g., when closure papers are required for program projects). With the additional requirements for variance analyses directed above, the Company also shall document policies for performing variance analyses.

6. Conclusion

Based on all of the above findings, the Department approves the Company's proposed plant additions for inclusion in rate base. As a result of this decision, it no longer is necessary to review the prudency of the Company's capital additions in the following CapEx dockets: D.P.U. 10-79 (2009 CY additions), D.P.U. 11-60 (CY 2010 additions), D.P.U. 12-48 (CY 2011 additions); D.P.U. 13-84 (CY 2012 additions), D.P.U. 14-95 (CY 2013 additions), and D.P.U. 15-84 (CY 2014 additions). Accordingly, upon issuance of this Order, these dockets shall be closed.

C. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including O&M expenses. These funds are either generated internally by a

company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds or for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a cash working capital component to the rate base calculation.

Cash working capital costs have been determined through either the use of a lead-lag study or a conventional 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has previously relied on a 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; Boston Gas Company, D.P.U. 88-67 (Phase I) at 35 (1988).[107] The Department has expressed concern that the 45-day convention, first developed in the early part of the 20th century, may no longer provide a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92, citing D.T.E. 98-51, at 15; D.P.U. 96-50 (Phase I) at 27. In recent years, lead-lag studies have resulted in savings for ratepayers by reducing the cash working capital requirement below the 45-day convention. D.P.U. 11-01/D.P.U. 11-02, at 163, citing D.P.U. 10-114, at 108; D.P.U. 10-70, at 78; D.P.U. 10-55, at 204-205; D.P.U. 09-39, at 114; D.P.U. 09-30, at 151-152; New England Gas Company, D.P.U. 08-35, at 38 (2009); D.T.E. 05-27, at 99-100. For these reasons, the Department requires all electric and gas companies serving more than 10,000

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107 When a fully developed and reliable lead-lag study is not available, FERC applies a 45-day convention to determine the cash working capital allowance. Carolina Power and Light Company, 6 FERC ¶ 61,154, at 61,296 (1979). As a result, companies occasionally refer to the 45-day convention as the "FERC convention." D.P.U. 11-01/D.P.U. 11-02, at 150 n.81.

customers to conduct a fully developed and reliable O&M lead-lag study.

D.P.U. 11-01/D.P.U. 11-02, at 164.

National Grid conducted a lead-lag study to determine its cash working capital requirements (Exh. NG-RRP-5). The Company proposed a cash working capital allowance of $68,019,916 using a net lead-lag factor of 5.70 percent, or 20.82 days (Exhs. NG-RRP-2, at 34 (Rev. 3); NG-RRP-8, at 6 (Rev. 3)).[108]

To determine its proposed cash working capital allowance, the Company first identified the following expense categories: (1) purchased power expense; (2) contract termination charges ("CTC");[109] (3) O&M expense; (4) transmission expense; (5) municipal taxes; (6) federal unemployment taxes; (7) state unemployment taxes; (8) FICA expense (both weekly and monthly);[110] (9) FICA and federal withholding (weekly and monthly); (10) state income tax withholding (weekly and monthly); and (11) incentive thrift (weekly and monthly) (Exh. NG-RRP-5, at 1 (Rev. 3)). The Company then determined a dollar-weighted period of time

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108 The Company reported a total distribution working capital requirement of $68,019,916 from a total dollar amount of $1,192,500,103, resulting in a CWC factor of 5.70 percent, which equates to 20.82 days (Exh. NG-RRP-2, at 34 (Rev. 3)).

109 The CTC resulted from a FERC-approved wholesale settlement that restructured the wholesale contractual relationship between New England Power Company ("NEP") and MECo in the context of the restructuring the electric utility industry in Massachusetts. NEP terminated its all-requirements contractual agreement with MECo in exchange for the payment of CTC by MECo. New England Power Company, FERC Docket Nos. ER97-678-000 (1997) and ER98-6-000 (1998); New England Power Company, D.T.E. 97-94, at 11 (1998).

110 FICA refers to the Federal Insurance Contributions Act. Under FICA, an employer withholds three separate taxes from employees' wages: (1) Social Security tax; (2) Medicare tax; and (3) Medicare surtax. 26 U.S.C. §§ 3110(a) and (b). Also, FICA requires that the employer pay a matching employer share of (1) the Social Security tax and (2) the Medicare tax. 26 U.S.C. §§ 3111(a) and (b).

between the end date for the receipt of service from supplier and the payment date, producing expense lag factors as a percentage of total days in a calendar year ranging between a negative 1.59 percent for monthly state income tax withholding and 24.43 percent for state unemployment taxes (Exh. NG-RRP-5, at 8-24 (Rev. 3)).

Next, the Company developed separate revenue lags for both MECo and Nantucket Electric representing the time delay between the mailing of customers' bills and the receipt of the billed revenues from customers (Exh. NG-RRP-5, at 3 (Rev. 3)). The revenue lags were obtained by first averaging the twelve-month balances of accounts receivable and then dividing the result by the average monthly electric revenues, producing collection lag components of 38.88 days associated with MECo's O&M expenses, 39.07 days associated with MECo's property and payroll taxes, and 23.16 days for Nantucket Electric's overall expenses (Exh. NG-RRP-5, at 3, 9, 26 (Rev. 3)). National Grid then added a billing lag of 1.41 days, representing the average lag from the date a meter is read to the date the bill is sent to the customer (Exh. NG-RRP-5, at 3 (Rev. 3)). The sums of the collection lags and service lags, represented as a percentage of the number of days in a calendar year, are 11.04 percent for MECo's O&M expenses, 11.09 percent for MECo's property and payroll taxes, and 6.73 percent for Nantucket Electric's overall expenses (Exh. NG-RRP-5, at 3, 9 (Rev. 3)).

The Company then subtracted the respective expense lag factors determined above from their respective revenue lag factors and then blended the results for both MECo and Nantucket, producing consolidated cash working capital factors for each expense category ranging between a negative 17.25 percent for federal unemployment taxes and 16.49 percent for municipal taxes (Exh. NG-RRP-5, at 2 (Rev. 3)). These cash working capital factors were then multiplied by the

pro forma expense associated with these expense categories, producing a total cash working capital allowance associated with operating expenses other than purchased power and CTC of $44,540,304 (Exh. NG-RRP-5, at 26, 30 (Rev. 3)).

As part of this analysis, National Grid computed a separate cash working capital factor associated with purchased power and CTC (Exh. NG-RRP-5, at 30 (Rev. 3)). To determine the cash working capital associated with purchased power, the Company determined a 19.78-day lag for purchased power and 3.05-day lag for CTC, representing 5.42 percent and 0.84 percent of a calendar year, respectively (Exh. NG-RRP-5, at 30 (Rev. 3)). Subtracting these percentages from MECo's revenue lag of 11.09 percent and Nantucket Electric's revenue lag of 6.73 percent as determined above produced purchased power cash working capital factors of 5.39 percent and 5.89 percent for MECo and Nantucket Electric, respectively, along with CTC cash working capital factors of 1.90 percent and 1.31 percent for MECo and Nantucket Electric, respectively (Exh. NG-RRP-5, at 30 (Rev. 3)). The Company then weighted the results for the two companies, producing an overall purchased power cash working capital factor of 5.34 percent and a CTC cash working capital factor of 1.88 percent (Exh. NG-RRP-5, at 1-2 (Rev. 3)). These cash working capital factors were then multiplied by the pro forma expense associated with these expense categories, producing cash working capital allowances of $56,248,188 associated with purchased power and a negative $54,067 for CTC (Exh. NG-RRP-5, at 1 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General does not challenge the Company's cash working capital calculations. However, she argues that if the Department allows National Grid to amortize its

outstanding hardship protected account balances, it also must adjust the Company's cash working capital allowance to recognize the fact that those accounts receivable will no longer affect the cash working capital requirement because removing those accounts will change the revenue lag (Attorney General Brief at 56-57; Attorney General Reply Brief at 33).

According to the Attorney General, the Company seeks to recover $40,982,476 in hardship protected accounts,[111] representing an annualized $491,789,712 in monthly accounts receivable balances that the Company uses as an input in the revenue lag calculation (Attorney General Brief at 57). The Attorney General argues that this balance represents 15.65 percent of the $3,142,435,793 in total revenues used to compute the revenue lag calculation (Attorney General Brief at 57). The Attorney General notes that the Company concedes that the recovery of the hardship protected accounts will have an effect on the cash working capital allowance (Attorney General Reply Brief at 33). Thus, the Attorney General asserts that if the Department accepts the Company's proposal to amortize its hardship accounts receivable balance, the accounts receivable balance used in the lead-lag study should be reduced by 15.65 percent ($491,789,712 / $3,142,435,793) to recognize the elimination of these accounts receivable from the overall balance of accounts receivable (Attorney General Brief at 57; Attorney General Reply Brief at 33). The Attorney General estimates that this elimination will reduce the average revenue lag by 15.65 percent, or 6.11 days (39.07 days x 0.1565 = 6.11 days) (Attorney General Brief at 57).

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111 The $40,982,476 is based on National Grid's second revision to its revenue requirement calculation, the most recent available schedule at the time initial briefs were being prepared (Exh. NG-RRP-2, at 24 (Rev. 2). As noted in Section VIII.J.1 below, based on the Company's most recent revenue requirement calculations, the Company claims a total hardship protected account balance of $52,027,414 (Exh. NG-RRP-2, at 24 (Rev. 3)).

b. Company

National Grid argues that the Department should adopt the Company's lead-lag results and the Company's proposed cash working capital allowance (Company Brief at 21). Further, National Grid contends that the Attorney General's recommendation to reduce the Company's revenue lag for hardship protected accounts is baseless (Company Brief at 58; Company Reply Brief at 45-46). According to the Company, future recovery of these accounts receivable will be appropriately reflected in a future cash working capital study, and that attempting to recognize a pre-funding of these recoveries in the cash working capital study in this case is unwarranted and will understate the Company's true cash working capital requirement (Company Brief at 59; Company Reply Brief at 46). Therefore, National Grid asserts that the Department should reject the Attorney General's recommendation (Company Brief at 59; Company Reply Brief at 46).

3. Analysis and Findings

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. D.P.U. 87-260, at 22-23. Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164. In the event that the lead-lag factor is not below 45 days, a company will face a high burden to justify the reliability of such a study and the reasonableness of the steps the company has taken

to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

The Attorney General argues that the Department should adjust the Company's cash working capital allowance to account for any recovery of hardship protected account receivable balance over 360 days (Attorney General Brief at 56-57; Attorney General Reply Brief at 33). As discussed further in Section VIII.J.3 below, the Department has allowed the Company to recover $40,607,637, representing the test year balances of these hardship accounts. Further, we find that the Company incurred the costs to provide the services that the hardship protected account receivables represent and will recover those costs prospectively over the five-year amortization period. To the extent that this recovery affects the revenue lag component of National Grid's cash working capital allowances, the change in the revenue lag component will be incorporated in future cash working capital studies. Therefore, the Department finds no need to recalculate the Company's revenue lag.

The Company has included in its lead-lag study cash working capital of $264,963,146 associated with energy efficiency activities (Exhs. NG-RRP-8, at 6 (Rev. 3); NG-RRP-5, at 8 (Rev. 3)). The Green Communities Act[112] specifies that energy efficiency-related costs must be collected through a fully reconciling funding mechanism, and the Department has approved the Energy Efficiency Surcharge ("EES") for this purpose. G.L. c. 25, §§ 19(a), 21(b)(2)(vii); Guidelines, §§ 2.9, 3.2.1. Therefore, the Department finds that these costs should be recovered through the EES and not through base rates. Accordingly, the Department has excluded $264,963,146 in energy efficiency-related expenses from the calculation of the Company's cash

[112] St. 2008, c. 169. An Act Relative to Green Communities.

working capital allowance. The exclusion of these expenses results in a composite lead-lag factor of 5.67 percent (see Schedule 6 below). The Department has reviewed the evidence in support of the Company's lead-lag study and, apart from the inclusion of energy efficiency-related cash working capital, we conclude that the Company properly calculated the revenue lags and expense leads (Exhs. NG-RRP-2, at 4, 34 (Rev.3); NG-RRP-5 (Rev 3); DPU-24-6; DPU-24-7, DPU-24-8, DPU-24-9; DPU-24-10; DPU-24-11; AG-24-14 & Att.; AG-24-15; AG-24-17; Tr. 6, at 872-873). The recalculated lead-lag factor of 5.67 percent is equivalent to 20.7 days, and thus lower than the results under the 45-day convention (Exh. NG-RRP-2, at 34 (Rev. 3); see also NG-RRP-5, at 1 (Rev. 3)).

Application of the cash working capital factor of 5.67 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $52,324,086 for the Company. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

D. Materials and Supplies

1. Introduction

The Department typically allows a company to include a representative level of its materials and supplies balance in rate base, which is determined using a 13-month average balance. Boston Edison Company, D.P.U. 19991, at 16 (1979); Housatonic Water Works Company, D.P.U. 86-235, at 3-4 (1987); High Wood Water Company, D.P.U. 1360, at 7-8 (1983); Western Massachusetts Electric Company, D.P.U. 1300, at 29 (1983). In its initial filing, National Grid reported a balance of $24,453,573 for its materials and supplies based on a test

year-end balance (Exh. NG-RRP-2, at 30; Tr. 6, at 943-944). The Company later reduced the balance to $23,231,040 based on a 13-month average (Exh. NG-RRP-2, at 30 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Department precedent requires a utility to use the 13-month average of materials and supplies inventories when calculating its rate base (Attorney General Brief at 22). The Attorney General claims that the Company's 13-month average balance of materials and supplies inventories is $22,852,218, and she urges the Department to use this balance in determining the Company's rate base (Attorney General Brief at 22, citing Exh. AG-2-3, Att.).

b. Company

The Company agrees that its materials and supplies balance should be based on a 13-month average (Company Brief at 20; Company Reply Brief at 16). However, the Company contends that the Attorney General erred in her calculation, and that the correct 13-month average balance is $23,231,039 (Company Brief at 20; Company Reply Brief at 16).[113]

3. Analysis and Findings

Utilities keep on hand various materials and supplies for use in the course of normal operations. The Department's long-standing practice has been to include a representative level of a company's materials and supplies balance in rate base. D.P.U. 19991, at 16. The

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113 In its initial brief, the Company claimed that the 13-month average balance amounted to $22,473,396 (Company Brief at 20). The Company revised the amount to $23,231,039 in its reply brief (Company Reply Brief at 16). The Company's schedules show the amount at $23,231,040, a minor discrepancy likely due to rounding (Exh. NG-RRP-2, at 30 (Rev. 3)).

Department allows this adjustment to compensate a utility for the carrying cost associated with its inventory. Because of the month-to-month fluctuations in this account, a 13-month average balance is used. D.P.U. 86-235, at 3-4; D.P.U. 1360, at 7-8; D.P.U. 1300, at 29.

The Department has reviewed the Company's schedules and the monthly balances provided in the record (Exhs. NG-RRP-2, at 30 (Rev. 3); AG-2-3, Att.). Based on our review, we find that the Attorney General's calculation is based on the 13-month period from June 2014 through June 2015, whereas the Company's calculation is based on the 13-month period beginning July 2014 through July 2015 (see Exhs. NG-RRP-2, at 30 (Rev. 3); AG-2-3, Att.). In other words, the Attorney General's 13-month period includes the twelve months of the test year (July 2014 through June 2015) and the month preceding the test year, whereas the Company's 13-month period includes the twelve months of the test year and the month following the test year.[114]

The Department's 13-month convention requires the use of monthly balances for the twelve months of the test year, plus the month preceding the first month of the test year in order to calculate the 13-month average balance. See D.P.U 10-114, at 101-102 (approving the company's 13-month average that included the month preceding the test year); D.P.U. 86-235, at 3-4 (requiring the company to include the balance from the month preceding the test year in calculating the 13-month average balance). The Department, therefore, calculates the 13-month average balance of materials and supplies using the Company's monthly balances from June 2014 to June 2015, and we arrive at a total of $22,852,218 (see Exh. AG-2-3, Att.).

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[114] Despite the representation provided by the Company regarding its calculations for the requested average in this matter, the Department notes that the Company's cost of service witness, when asked at the evidentiary hearings, calculated an average balance of $22,852,218 (Tr. 9, at 1438-1439).

Accordingly, the Department will further reduce the Company's proposed materials and supplies balance by $378,821.

E. Asset Retirement Obligations

1. Introduction

As part of its plant in service, the Company has included $332,000 in asset retirement obligations ("ARO") associated with general plant (Exh. NG-RRP-2, at 27, 30 (Rev. 3)).[115] An ARO represents estimated costs of future retirements that are not otherwise provided for in the net salvage factor used to derive the Company's depreciation accrual rates. D.P.U. 09-39, at 102. No party commented on brief about the Company's inclusion of AROs in its plant investment.

2. Analysis and Findings

The Uniform System of Accounts for Electric Companies ("USOA-Electric Companies"), codified as 220 C.M.R. § 51.00 et seq., specifies that AROs associated with general plant are to be booked to Account 399 (18 CFR Pt. 101, Balance Sheet Chart of Accounts, Electric Plant Instructions, Sec. 10(B)(2)).[116] Accounting requirements, however, do not necessarily dictate ratemaking treatment. D.P.U./D.T.E. 97-95, at 77; Massachusetts Electric Company, D.P.U. 92-78, at 79-80 (1992); Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979). The accounting systems prescribed by the Department, including the USOA-Electric

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115 The Company reported no accumulated depreciation associated with its ARO as of the end of the test year (Exh. NG-RRP-2, at 27 (Rev. 3)).

116 The Department has adopted the USOA-Electric Companies prescribed by FERC, with several modifications. 220 C.M.R. § 51.01(1). The applicable FERC system of accounts, entitled Uniform System of Accounts Prescribed For Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, are set forth at 18 CFR, Part 101.

Companies, represent systems whereby costs are categorized to provide the Department with information on utility operations and aid in the review of utility costs. The Department's ratemaking process takes into consideration many factors other than account balances. Therefore, the booking of a particular expense in accordance with the USOA-Electric Companies implies no judgment as to the reasonableness of that cost in a given instance, nor does it establish the per se treatment of that cost for ratemaking purposes. D.P.U./D.T.E 97-95, at 77; see also Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997).

The Company's AROs represent estimated future removal costs in the form of balance sheet entries that do not represent plant in service. D.P.U. 09-39, at 103-104; see also Western Massachusetts Electric Company, D.T.E. 05-9, at 13 (2005). National Grid's proposal, in effect, seeks not only recognition of its future retirement costs, but also recovery of carrying charges on those future costs. Regardless of the requirements of financial reporting, there is no basis to provide any regulated utility with a return on costs that have not yet been incurred. D.P.U. 09-39, at 103-104. Moreover, the Department is not persuaded that the net salvage factors used in the Company's depreciation study (see Section VIII.E below) are insufficient to recognize the cost of retiring the underlying assets.

Based on the foregoing analysis, the Department finds that the Company has failed to justify the inclusion of ARO in rate base. Accordingly, the Department reduces National Grid's proposed rate base by $332,000.

VIII. OPERATIONS AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach recognizes that the different components of compensation (i.e., wages and benefits) are, to some extent, substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55.

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 103 (1992); D.P.U. 92-78, at 25-26.

National Grid's employee compensation program is known as the "Total Rewards Program" (Exh. NG-MPH-1, at 6). The Total Rewards Program encompasses fixed pay, variable pay, medical and dental insurances, life insurance, a 401(k) retirement savings plan, and pensions and post-retirement benefits (Exh. NG-MPH-1, at 6).

2. Non-Union Wages

a. Introduction

During the test year, National Grid booked $69,182,833 in payroll expense for non-union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $6,961,426 in payroll expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated, respectively, $61,428,586 and $792,821 to the Company's test year payroll expense (Exh. NG-RRP-2, at 9-10).[117]

The Company initially proposed an increase to non-union payroll expense of $3,710,260 based on: (1) a non-union wage increase of 3.5 percent effective July 1, 2016; and (2) the inclusion of 27 approved non-union NGSC positions vacated during the test year and unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 28-29; NG-RRP-2, at 8-10; NG-MPH-1, at 8-9; DPU-8-20, Att. at 1).[118] Based on revisions made during the proceeding, National Grid now proposes to increase non-union payroll expense by $1,965,104 (Exh. NG-RRP-2, at 8-10 (Rev. 3)). This change represents a reduction to the 2016 non-union wage increase from 3.5 percent to 3.2 percent, a reduction to the approved non-union NGSC positions from 27 to 25, and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 8-10 (Rev. 3); NG-MPH-Rebuttal-1, at 8; NG-MPH-Rebuttal-3; NG-RRP-Rebuttal-1, at 15; DPU-8-20; AG-22-1, Att. at 1). The non-union wage increases were determined based on an industry compensation assessment performed by Towers Watson on

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[117] Minor discrepancies in any of the amounts appearing in this section are due to rounding.

[118] Proposed adjustments for all approved positions are addressed in Section VIII.A.4 below.

behalf of the Company, projected increases in non-union base salaries, and an historical comparison of non-union base wage increases to union base wage increases (Exhs. NG-MPH-1, at 8-13; NG-MPH-2; NG-MPH-7; NG-MPH-8).

b. Positions of the Parties

i. Attorney General

The Attorney General's comments regarding non-union wage adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i below (Attorney General Brief at 24-25).

ii. Company

The Company argues that its non-union compensation is market competitive and that the cost of service includes known and measurable changes occurring before the mid-point of the rate year (Company Brief at 94). Specifically, National Grid claims that the Towers Watson analyses demonstrate that the salary range for each of its six employee bands is competitive with the median market rate (Company Brief at 96, citing Exh. NG-MPH-1, at 6-7, 9, 12). Further, the Company argues that the aggregate non-union increase of 3.2 percent scheduled to take effect on July 1, 2016, is based on market studies currently available to National Grid and closely aligned with the relevant markets (Company Brief at 97, citing Exhs. NG-MPH-1, at 9, 12-13; NG-MPH-7; DPU-8-26). The Company asserts that its non-union salary increase is reasonable and should be approved by the Department for inclusion in the Company's cost of service (Company Brief at 97).

c. Analysis and Findings

The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that: (1) non-union salary increases are scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, that there is an express commitment by management to grant the increase; (3) there is an historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. D.P.U. 85-266-A/85-271-A at 107; D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

The Company provided a management commitment letter stating that a 3.2 percent payroll increase for non-union Company employees would take place on July 1, 2016 (Exh. NG-MPH-Rebuttal-3). Additionally, the Company provided a ten-year history of union and non-union wage increases (Exh. NG-MPH-8). Between 2006 and 2015, annual union wage increases were between 2.5 percent and 3.25 percent, and non-union wage increases were between 0.43 percent and 3.9 percent (Exh. NG-MPH-8). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

Finally, with respect to the reasonableness of the non-union wage increase, the Company sets total cash compensation equal to the median of the marketplace (Exh. NG-MPH-1, at 9). Specifically, National Grid participates in an annual market study performed by an independent third-party vendor, Towers Watson, and, using that study, compares overall pay of certain

benchmark positions to the 50th percentile of overall pay for comparable jobs in similarly sized companies (Exh. NG-MPH-1, at 9). The Towers Watson study concluded that the Company's non-union compensation levels are competitive against similarly sized energy services companies (those with revenues greater than $6 billion) as well as total sample energy services companies (Exh. NG-MPH-2, at 5). The Department determines that National Grid's review of industry compensation data is sufficient to confirm the reasonableness of its non-union salary levels. See D.P.U. 10-55, at 245; D.T.E. 05-27, at 109; D.T.E. 02-24/25, at 94.

Based on the above, we find that National Grid has demonstrated that: (1) there is an express management commitment to grant a 3.2 percent non-union wage increase; (2) there is an historical correlation between union and non-union payroll increases; and (3) the non-union wage increases are reasonable. Accordingly, we allow the Company's adjusted non-union payroll expense, subject to our findings below on staffing levels.

3. Union Wages

a. Introduction

During the test year, National Grid booked $72,861,689 in payroll expense for union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $57,915,195 in payroll expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $11,965,079 and $2,981,415, respectively, to the Company's test year payroll expense (Exh. NG-RRP-2, at 9-10).

The Company initially proposed an increase to test year union payroll expense of $7,285,812 based on: (1) Company and NGSC union wage increases of 2.5 percent effective May 12, 2016; (2) affiliated companies' union wage increases of 2.0 percent and 2.5 percent

effective April 1, 2016 and May 12, 2016, respectively; (3) the inclusion of five approved union Company positions vacated during the test year and unfilled as of June 30, 2015; and (4) nine approved union NGSC positions vacated during the test year and unfilled as of June 30, 2015[119] (Exhs. NG-RRP-1, at 27-29; NG-RRP-2, at 8-10; NG-MPH-1, at 14-15; DPU-8-19, Att.; DPU-8-20, Att. at 1). Based on revisions made during the proceeding, National Grid now proposes to increase union payroll expense by $7,001,070 (Exh. NG-RRP-2, at 8-10 (Rev. 3)). This change represents a reduction to the total approved union positions from 14 to twelve and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 8-10 (Rev. 3); DPU-8-19, Att.; DPU-8-20; AG-22-1, Att. at 1). The union wage increases were determined by currently effective collective bargaining agreements (Exhs. NG-MPH-1, at 14-15; AG-1-42, Atts. 1-17).

b. Positions of the Parties

i. Attorney General

The Attorney General's comments regarding union wage adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i, below (Attorney General Brief at 22-25).

ii. Company

The Company states that its union compensation is market competitive and that the cost of service includes known and measurable changes occurring before the mid-point of the rate year (Company Brief at 94). Specifically, National Grid argues that the analysis provided demonstrates that the hourly rates paid to its union employees are within the range of

[119] Proposed adjustments for all approved positions are addressed in Section VIII.A.4 below.

surrounding utilities (Company Brief at 98, citing Exh. NG-MPH-9).[120] The Company also claims that it has illustrated the reasonableness of union wage levels (Company Brief at 98). Further, National Grid contends that the proposed union wage increases are based on currently effective collective bargaining contracts and, therefore, satisfy the Department's known and measurable requirement for post-test year union wage adjustments (Company Brief at 95, 97). Based on these considerations, the Company asserts that its union compensation costs are reasonable and should be approved by the Department for recovery (Company Brief at 97).

c. Analysis and Findings

The Department's standard for post-test year union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the date of the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted before April 1, 2017, the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. NG-MPH-1, at 14-15; AG-1-42, Atts. 1-17). Further, because the union payroll increases are based on signed collective bargaining agreements, the Department finds that the proposed increases are known and measurable (Exh. AG-1-42, Atts. 1-17). Finally, with respect to the reasonableness of the union

[120] For seven positions, the Company compared its union wage pay levels with pay levels for nine other New England electric utilities (seven investor owned and two municipals), calculating median, average, and maximum pay rates for each position (Exh. NG-MPH-9).

wage increases, National Grid submitted a comparison of its union salaries to utilities throughout New England (Exhs. NG-MPH-1, at 15; NG-MPH-9). National Grid's hourly pay rates are comparable to those of other utility companies in the region for the selected union job titles (Exh. NG-MPH-9). Thus, we find that the Company has demonstrated the reasonableness of its union wage increases.

Based on the above, the Department finds that National Grid's union wage increases (1) take effect before the midpoint of the first twelve months after the rate increase; (2) are known and measurable; and (3) are reasonable. Accordingly, we allow the Company's proposed union payroll adjustments, subject to our findings below on staffing levels.

4. Employee Staffing Levels

a. Introduction

National Grid proposed adjustments for changes in staffing levels after the test year, calculating the wage expense based on the employee complement as of June 30, 2015 (Exh. NG-RRP-1, at 27). The Company initially proposed to include $362,627 in wages and salaries for five approved union Company positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 27; NG-RRP-2, at 8). Additionally, the Company initially proposed to include $3,060,864 in wages and salaries for nine approved union NGSC positions and 27 approved non-union NGSC positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-1, at 28-29; NG-RRP-2, at 9; DPU-8-20, Att.). Based on revisions made during the proceeding, National Grid now proposes to include $267,010 in wages and salaries for four approved union Company positions (Exhs. NG-RRP-2, at 8 (Rev. 3); NG-RRP-Rebuttal-1, at 36). The Company also proposes to

include $544,618 in wages and salaries for eight approved union NGSC positions and 25 approved non-union NGSC positions that were vacated during the test year and remained unfilled as of June 30, 2015 (Exhs. NG-RRP-2, at 9 (Rev. 3); NG-RRP-Rebuttal-1, at 15; AG-22-1, Att. at 1). These changing in staffing levels, and the corresponding decreases in expenses, were the result of position cancellations and a correction to the allocation of NGSC salaries to the Company's payroll expense (Exhs. NG-RRP-2, at 9 (Rev. 3); DPU-8-20; AG-22-1, Att. at 1).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject the Company's proposal to include four Company and 33 NGSC vacant positions in its cost of service, including proposed increases to payroll expense, employee benefits costs, and payroll taxes (Attorney General Brief at 22-24). Specifically, the Attorney General claims that the Company has not established that the filling of the vacant positions is outside the normal ebb and flow of its workforce complement (Attorney General Brief at 23). Further, the Attorney General contends that the Company has provided no evidence that the employee level as of June 30, 2015, which does not include the vacant positions, is abnormal or unreflective of typical vacancy conditions (Attorney General Brief at 25). Thus, the Attorney General asserts that all four Company and 33 NGSC positions should be excluded from the cost of service in this case (Attorney General Brief at 23 and 25). The Attorney General recommends a pro forma wage and salary expense reduction of $145,272 to eliminate the four proposed Company positions, as well as reductions of $38,335 and $10,825 in associated employee benefits expenses and payroll taxes, respectively

(Attorney General Brief at 24, citing Exh. AG-DJE-Rebuttal-1, Sch. DJE-1). Additionally, the Attorney General recommends a pro forma wage and salary expense reduction of $374,509 to eliminate the 33 proposed NGSC positions, as well as reductions of $75,887 and $27,906 in associated employee benefits expenses and payroll taxes, respectively (Attorney General Brief at 25, citing Exhs. AG-DR-Rebuttal-1, at 4; NG-RRP-Rebuttal-2, column NG(c)).

ii. Company

The Company argues that its proposal to include four Company and 33 NGSC positions in the cost of service is narrower than the Attorney General suggests, is backed by Department precedent, and should be approved by the Department (Company Brief at 70-71). National Grid agrees with the Attorney General that is it reasonable to assume that the Company and NGSC will always have vacant positions (Company Brief at 70). However, the Company states that it does not seek to make adjustments for all Company and NGSC positions that were vacant as of June 30, 2015, but rather a narrow subset of those positions (Company Brief at 70). The Company maintains that its proposal covers only those Company and NGSC positions that were filled during the test year, were vacant as of June 30, 2015, and were filled prior to the filing of the instant case or prior to the expiration of this proceeding (Company Brief at 70). Additionally, National Grid contends that its request is similar to one previously approved by the Department for New England Gas Company (n/k/a Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities) (Company Brief at 71, citing D.P.U. 10-114, at 135). National Grid argues that New England Gas Company's proposal to include costs associated with a position filled during the 2009 test year, vacated as of 2010, and then filled by a temporary employee is analogous to the Company's proposal in this proceeding (Company Brief

at 71). Further, National Grid argues that the Department's approval of New England Gas Company's proposal renders the Company's own wage and salary adjustments appropriate (Company Brief at 71). Therefore, the Company asserts that the Department should approve the proposed adjustments (Company Brief at 71).

c. Analysis and Findings

Employee staffing levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. Massachusetts-American Water Company D.P.U. 88-172, at 12 (1989); D.P.U. 1270/1414, at 16-17. In recognition of this variability, the Department generally determines payroll expense on the basis of test year employee levels, unless there has been a significant post-test year change in the number of employees that falls outside the normal ebb and flow of a company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

National Grid asserts that the Department's approval of New England Gas Company's proposal to include a vacancy is analogous to its own proposal to include 37 vacancies (Company Brief at 71, citing D.P.U. 10-114, at 135). In fact, New England Gas Company's proposal was different in two significant ways. First, in D.P.U. 10-114, the position proposed for inclusion in the pro forma cost of service was not vacant at the end of the 2009 test year, while the positions in the instant case were vacant at the end of National Grid's test year. D.P.U. 10-114, at 135. Therefore, the positions in the instant case, unfilled on June 30, 2015, are rightfully excluded from an employee complement taken on that date. Additionally, New England Gas Company had removed temporary employee costs from 175 contract labor accounts, and the purpose of the proposed adjustment was to move the temporary employee cost into that company's pro forma payroll expense account. D.P.U. 10-114, at 135. Therefore, the

Department's decision in D.P.U. 10-114 allowed a proposal to move incurred, known, and measurable salary costs to the correct, permanent payroll expense account. This proposal is fundamentally different from National Grid's proposal in the instant case to increase the test year-end employee complement and associated payroll expense by 37 vacant positions.

Additionally, the Company argues that the 37 positions it proposes to include in its pro forma cost of service are appropriate because these positions were in place during the test year, temporarily vacated as of June 30, 2015, and filled before the expiration of this case (Company Brief at 70). The selection of the test year, however, is largely a matter of a distribution company's choice. See D.P.U. 07-50-A at 51. Of its own volition, the Company selected the twelve-month period ending June 30, 2015, as the test year (see Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6). Subsequently, National Grid annualized base wages of its employee complement as of June 30, 2015 (Exh. NG-RRP-1, at 27). Any changes to the employee complement after this date would be considered a post-test year change, including those positions vacated as of June 30, 2015 and filled thereafter. Therefore, the Company must demonstrate that the filling of the 37 positions constitutes a significant post-test year change above and beyond the normal ebb and flow of employment levels in order for the Department to grant the proposed adjustments to payroll expense. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

The Company made no explicit effort to demonstrate that the post-test year changes to employee levels were significant or outside the normal ebb and flow of the workplace. Nonetheless, the Department has analyzed the impact of filling the proposed vacancies on payroll expense levels as well as employee staffing levels. The four proposed union vacancies'

wages and salaries represent 0.46 percent of total test year union payroll O&M expense (Exh. NG-RRP-2, at 8 (Rev. 3)). The Company's share of the eight proposed union and 25 proposed non-union vacancies' wages and salaries represents 0.82 percent and 0.73 percent of the Company's shares of total union and non-union test year NGSC payroll O&M expense, respectively (Exh. NG-RRP-2, at 9 (Rev. 3)). These amounts, both less than one percent, do not represent significant changes to test year payroll expense. D.P.U. 90-121, at 80-81. Alternatively, using monthly employee levels, the four proposed union vacancies constitute 0.37 percent of the 1,070 union Company employees present in the last month of the test year (Exh. DPU-8-21, Att.). The eight proposed union and 25 proposed non-union vacancies comprise 0.57 percent of the 1,405.5 union and 0.66 percent of the 3,782 non-union NGSC employees present in the last month of the test year (Exh. DPU-8-22, Att.). These amounts, both less than one percent, also do not represent significant changes to test year employee levels.

Based on evidence provided in the instant case, the Department concludes that the 37 proposed vacancies do not constitute a significant post-test year change. Thus, the Department rejects the portion of the proposed salary and wage adjustments related to the approved positions vacated during the test year. The Department reduces the Company's proposed cost of service by $526,169.[121] In accordance with the above staffing level

[121] Of this amount, $145,273 reduces proposed adjustments to MECo and Nantucket Electric payroll expense and $380,896 reduces proposed adjustments to the Company's share of NGSC payroll expense. The two reductions are further broken down as follows: (1) $267,010 proposed union vacancy salaries * 1.025 union wage increase * 0.5308 O&M percentage of base wages = $145,273 reduction to proposed MECo and Nantucket Electric payroll expense adjustment; (2) ($97,542 proposed union vacancy salaries * 1.025 union wage increase * 0.5577 O&M percentage of base wages = $55,756) + ($447,076 proposed non-union vacancy salaries * 1.032 non-union wage increase * 0.7047 O&M percentage of base wages = $325,140) = $380,896 reduction to proposed

adjustments, concordant adjustments to health care expense will be addressed below. Further, concordant adjustments to payroll tax expense, group insurance expense, and employee thrift expense will be addressed in the payroll taxes section, below.

5. Variable Compensation

a. Introduction

National Grid's variable compensation program is called the "Annual Performance Plan" (Exh. NG-MPH-1, at 17). There are three components to the variable pay program: (1) performance metrics tied to overall Company financial results, including earnings per share and ROE; (2) performance metrics based on safety, reliability, customer responsiveness, cost competitiveness, and stewardship (collectively referred to as "Elevate targets"); and (3) performance metrics based on individual objectives (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-6, at 1). The Company's non-union employees are classified into six salary categories ("Salary Bands") (see Exh. NG-MPH-1, at 19-20). Salary Band A consists of National Grid's most senior executives, Salary Bands B and C includes officers/directors, and Salary Bands D through F include managers, analysts, and all other non-union Company employees (Exh. NG-MPH-1, at 19-20). Each of the six Salary Bands, as well as all union employees, are assigned a particular combination of the above three components to arrive at the total Annual Performance Plan award (Exh. NG-MPH-1, at 19, 21). An eligible employee's maximum Annual Performance Plan award ranges from five percent to 40 percent of the same year's base wages, and varies by Salary Band (Exhs. NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-6, at 1).

Company share of NGSC payroll expense adjustment (see Exh. NG-RRP-2, at 8-9 (Rev. 3)).

For employees in Salary Bands A, B, and C, 20 percent of the Annual Performance Plan award is based on attaining Elevate targets, 40 percent is based on attaining financial metrics, and 40 percent is based on attaining employee-specific goals (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1). For employees in Salary Bands D, E, and F, 50 percent of the Annual Performance Plan award is based on attaining Elevate targets and 50 percent is based on attaining employee-specific objectives (Exhs. NG-MPH-1, at 19; NG-MPH-6, at 1). In the case of all union employees, 100 percent of the Annual Performance Plan award is based on attaining Elevate targets (Exh. NG-MPH-1, at 19).

During the test year, the Company booked $10,638,165 in variable compensation for non-union personnel (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $491,622 in variable compensation expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $9,737,387 and $409,156, respectively, to the Company's test year variable compensation expense (Exh. NG-RRP-2, at 9-10). During the test year, National Grid also booked $2,349,884 in variable compensation for union personnel (Exh. NG-RRP-2, at 8-10). Of that amount, MECo and Nantucket Electric directly incurred $1,992,598 in variable compensation expense (Exh. NG-RRP-2, at 8). NGSC and other National Grid plc affiliates allocated $230,535 and $126,751, respectively, to the Company's test year variable compensation expense (Exh. NG-RRP-2, at 9-10).

National Grid initially proposed to increase non-union and union variable compensation by $346,642 and $56,160, respectively, to recognize the proposed 3.5 percent and 2.5 percent increases to test year wages (Exh. NG-RRP-2, at 8-10). Based on revisions made during the proceeding, the Company now proposes to increase non-union and union variable compensation

by $316,929 and $56,160, respectively (Exh. NG-RRP-2, at 8-10 (Rev. 3)). As noted above, this change results from a reduction to the 2016 non-union wage increase from 3.5 percent to 3.2 percent (Exhs. NG-RRP-2, at 8-10 (Rev. 3); NG-MPH-Rebuttal-1, at 8; NG-MPH-Rebuttal-3). Additionally, National Grid's proposed cost of service removes variable compensation for Salary Band A employees, the Company's most senior executives (Exh. NG-MPH-1, at 20).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should remove the financial component of incentive compensation costs from National Grid's cost of service (Attorney General Brief at 31). The Attorney General claims that the Department has made it clear that if financial goals are used in incentive plans, they should be used as a threshold component only (Attorney General Brief at 31). Further, she notes that while the Company's efforts to reduce the portion of variable pay tied to meeting financial goals are commendable, the record shows that 40 percent of the potential incentive plan awards for Salary Bands B and C employees are based on financial targets such as earnings per share and ROE (Attorney General Brief at 34). The Attorney General maintains that the goals of earnings per share and ROE clearly focus on shareholder interests (Attorney General Brief at 35). Thus, she argues that the costs associated with the attainment of such goals should be excluded from costs charged to Massachusetts ratepayers (Attorney General Brief at 35). Specifically, she recommends reducing the Company's pro forma cost of service by $847,532 (Attorney General Brief at 35). The recommended reduction includes $756,422 to remove variable pay associated with achieving

financial metrics and $91,110 in concordant adjustments to group insurance, employee thrift, and payroll taxes (Attorney General Brief at 35).

ii. Company

The Company argues that the costs of its incentive compensation plan are reasonable and that the plan itself is reasonably designed to encourage good employee performance (Company Brief at 100). National Grid contends that excluding the entire variable pay component for its most senior executives, as it did in D.P.U. 09-39, contributes to the reasonableness of its overall incentive compensation cost level included in rates (Company Brief at 100). The Company also claims that the current incentive compensation structure is similar to plans previously approved by the Department in which a higher percentage of non-union variable pay was tied to meeting financial performance objectives (Company Brief at 101, citing D.P.U. 10-55; D.P.U. 09-39).

Nonetheless, National Grid recounts several steps it took to modify its variable pay program to better align with the Department's expectations following the Department's decision in D.P.U. 10-55 (Company Brief at 101). These steps include reducing the amount of variable pay tied to financial performance from 60 percent for Band A and B employees and 50 percent for Band C employees to 40 percent across all employees in Bands A through C, eliminating financial targets altogether for employees in Bands D through F, and adding customer satisfaction, safety and reliability targets for its officers and directors (Company Brief at 101). Finally, with respect to the financial metrics themselves, the Company states that it replaced line of business financial targets with earnings per share and ROE goals to emphasize quality of financial management, particularly in the area of internal cost containment (Company Brief at 101). Finally, National Grid claims that implementing cost containment measures, in pursuit

of a ROE goal, will delay base rate cases or limit the impact of those cases and thus will benefit customers (Company Brief at 102).

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if (1) the expenses are reasonable in amount, and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

The Department must first determine whether the costs associated with National Grid's Annual Performance Plan are reasonable in amount. First, the Company does not seek to recover variable pay for its most senior executives (Exh. NG-MPH-1, at 20). Next, the Company has provided the 2015 results of a Towers Watson assessment that compared total cash compensation, defined as base pay plus any incentive or variable compensation, to the median of the marketplace (Exh. NG-MPH-2, at 5). The Towers Watson study concluded that National Grid's non-union compensation levels are competitive against similarly sized energy services companies (those with revenues greater than $6 billion) as well as total sample energy services companies (Exh. NG-MPH-2, at 5). Based on our review of this evidence, the Department finds that National Grid has demonstrated that its incentive compensation costs are reasonable in amount. See D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

The Department must next determine whether the Company's Annual Performance Plan is reasonable in design. A portion of the Annual Performance Plan expense is tied to meeting

financial metrics such as earnings per share and ROE (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1). The Attorney General argues that the Department should deny recovery of variable compensation related to financial metrics because the Company chose to continue to make financial goals components of the plan design upon which payouts are based, despite what the Attorney General maintains is the Department's clear parameters in a decision involving the Company's affiliate, Boston Gas Company (Attorney General Brief at 31, citing D.P.U. 10-55, at 253-254).

The Department has articulated its expectations on the use of financial targets in variable compensation plans and the burden to justify recovery of such costs in rates. D.P.U. 15-80/D.P.U. 15-81, at 115-116; D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Specifically, where companies seek to include financial goals as a component of incentive compensation design, the Department expects to see the attainment of such goals as a threshold component, with job performance standards designed to encourage good employee performance (e.g., safety, reliability, customer satisfaction goals) used as the basis for determining individual incentive compensation awards. D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Companies that nonetheless wish to maintain financial metrics as a component of the formula used to determine individual incentive compensation must be prepared to demonstrate direct ratepayer benefit from the attainment of these goals or risk disallowance of the related incentive compensation costs. D.P.U. 13-90, at 83; D.P.U. 11-01/D.P.U. 11-02, at 193; D.P.U. 10-70, at 106; D.P.U. 10-55, at 253-254.

National Grid's financial metrics do not operate as a threshold component, but rather are a direct component of overall incentive compensation plan design (Exh. NG-MPH-1, at 19-20). While we acknowledge the Company's decisions to reduce the portion of variable pay tied to financial metrics and to introduce customer satisfaction, safety, and reliability targets for officers and directors, the financial metrics still represent 40 percent of the incentive compensation payment calculation for employees in Salary Bands A, B, and C (Exhs. NG-MPH-1, at 19; NG-MPH-4, at 1; NG-MPH-5, at 1; NG-MPH-Rebuttal-1, at 6). Thus, National Grid must demonstrate direct ratepayer benefit from the attainment of earnings per share and ROE goals to recover this portion of incentive compensation costs from ratepayers. D.P.U. 10-55, at 253-254. The Company acknowledges this recovery standard and contends that customers benefit from cost containment measures that may be implemented in the pursuit of ROE and earnings per share goals, but has made no substantive demonstration of this claim (Exhs. NG-MPH-Rebuttal-1, at 5-6; DPU-8-28). Therefore, consistent with Department precedent, the Department finds that National Grid has failed to demonstrate that the financial metrics components of its incentive compensation plan are reasonably designed to encourage good employee performance and result in direct ratepayer benefits.

Accordingly, the Department reduces National Grid's proposed cost of service by $754,230[122] to remove the portion of the Company's incentive compensation expense attributable to the earnings per share and ROE measures (see Exh. DPU-8-29). In recognition of the above variable compensation expense adjustments, concordant adjustments to payroll tax expense will be addressed below.

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[122] The Department's adjustment incorporates the non-union salary update of 3.2 percent provided in Exhibit NG-RRP-2, at 8-10 (Rev. 3).

B. Payroll Taxes

1. Introduction

During the test year, National Grid booked $10,584,314 in adjusted payroll taxes after removing $163,969 in qualified storm costs eligible for recovery through the storm fund (Exh. NG-RRP-2, at 29). The Company originally proposed to increase its cost of service by $819,226 to recognize the additional payroll taxes associated with its pro forma wage and salary expense (Exhs. NG-RRP-1, at 39; NG-RRP-2, at 29). Based on revisions made during the proceeding, National Grid now proposes to increase payroll tax expense by $388,624 (Exh. NG-RRP-2, at 29 (Rev. 3)). This change represents the removal of energy efficiency-related payroll taxes and the application of wage-based caps to several payroll tax categories (Exhs. NG-RRP-2, at 29 (Rev. 3); AG-20-16; Tr. 9 at 1420-1421; RR-DPU-2).

2. Positions of the Parties

a. Attorney General

As stated in Section VIII.A.4.b.i above, the Attorney General argues that the Department should reject National Grid's proposal to include four Company and 33 NGSC vacant positions in its cost of service (Attorney General Brief at 24-25). The Attorney General subsequently recommends associated payroll, payroll tax, and other employee compensation-related expense reductions (Attorney General Brief at 24-25). The Attorney General recommends a payroll tax expense reduction of $38,731, consisting of $10,825 in payroll taxes associated with the four Company vacant positions, and $27,906 in payroll taxes associated with the 33 NGSC vacant positions (Attorney General Brief at 24-25, citing Exhs. AG-DJE-Rebuttal-1, Sch. DJE-1; NG-RRP-Rebuttal-2, column NG(c)).

b. Company

National Grid argues that it calculated the change in payroll tax in proportion to its proposed labor and incentive compensation adjustments (Company Brief at 93, citing Exhs. NG-RRP-1, at 39; NG-RRP-2, at 29 (Rev. 2)). The Company claims that it increased payroll tax expense by 6.31 percent to account for a 6.31 percent increase in rate year salaries and wages as compared to test year salaries and wages (Company Brief at 93). National Grid argues that the Department should approve the Company's proposed adjustments to taxes other than income taxes (Company Brief at 93).

3. Analysis and Findings

The Department has examined the record related to the Company's payroll tax calculations (e.g., Exhs. NG-RRP-2, at 29 (Rev. 3); DPU-8-31; AG-20-16; Tr. 1, at 108-117; Tr. 9, at 1420-1421; RR-DPU-1; RR-DPU-2), and we find that three revisions must be made. First, the Department revises the percentage change in rate year salaries and wages used to calculate the initial payroll tax adjustment (Exh. NG-RRP-2, at 29, line 4 (Rev. 3)). Second, the Department revises the percentage of rate year payroll expense subject to increased Social Security tax used to calculate the final payroll tax adjustment (RR-DPU-1, Att. at 183; RR-DPU-2, Att.). Third, the Department will make necessary revisions to the Company's group insurance expense and employee thrift expense. These are explained in further detail below.

First, based on staffing level and incentive compensation expense adjustments discussed in Sections VIII.A.4.c and VIII.A.5.c above, the Department reduces the Company's most recent

rate year O&M salaries and wages figure by $1,280,399.[123] This reduction yields a revised percentage change in rate year salaries and wages of 5.41 percent.[124] Second, based on the disallowance of 37 vacancies discussed in Section VIII.A.4.c above, the Company's most recent calculation of rate year labor subject to payroll tax must not include these vacancies' salaries and wages (RR-DPU-1, Att. at 183). Removing these salaries and wages yields a revised percentage of rate year payroll expense subject to increased Social Security tax of 54.8 percent.[125] Applying these two changes yields a final payroll tax expense adjustment of $332,952.[126] Therefore, the Department reduces the Company's proposed cost of service by $55,672 ($388,624 - $332,952).

Finally, in accordance with the above revision to the percentage change in rate year salaries and wages used to calculate the payroll tax adjustment, the Department makes necessary revisions to group insurance expense and employee thrift expense adjustment calculations that

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123 This amount includes a $526,169 staffing level reduction to payroll expense and a $754,230 variable compensation reduction to payroll expense (see also Exh. DPU-8-29).

124 (($151,010,695 proposed rate year O&M wages - $1,280,399 Department reduction to rate year O&M wages) - $142,044,523 test year O&M wages)/$142,044,523 = 0.0541 percentage change in rate year O&M wages (see Exh. NG-RRP-2, at 29, line 8-13 (Rev. 3)).

125 $813,257,570 total rate year labor below SS-FICA cap /$1,482,901,070 total rate year SS-FICA taxable labor = 0.548 proportion of rate year labor subject to tax increase (see RR-DPU-1, Att. at 183).

126 ($7,773,787 adjusted test year FICA expense * 0.0541 percentage change in rate year O&M wages * 0.548 proportion of rate year labor subject to tax increase = $230,646) + ($1,818,063 adjusted test year Medicare expense * 0.0541 percentage change in rate year O&M wages = $98,357) + ($68,744 adjusted test year NY Commuter Tax * 0.0541 percentage change in rate year O&M wages = $3,719) + ($4,236 adjusted test year Other payroll tax expense * 0.0541 percentage change in rate year O&M wages = $229) = $332,952 final payroll tax adjustment (see Exh. NG-RRP-2, at 29, line 5d (Rev. 3); RR-DPU-1, Att. at 183; RR-DPU-2).

use the percentage change figure. Using the 5.41 percentage change figure to increase adjusted test year expense, the Department finds that National Grid's final group insurance expense adjustment is equal to $74,455.[127] The Company proposed an adjustment to group insurance expense of $83,378 (Exh. NG-RRP-2, at 12 (Rev. 3)). Therefore, the Department reduces the Company's proposed cost of service by $8,923 ($83,378 - $74,455). Further, the Department increases National Grid's adjusted test year employee thrift expense by 5.41 percent to determine the final employee thrift expense adjustment of $259,221.[128] The Company proposed an adjustment to employee thrift expense of $302,492 (Exh. NG-RRP-2, at 13 (Rev. 3)). The Department thus reduces the Company's proposed cost of service by $43,272 ($302,492 - $259,221).

C. Medical and Dental Expenses

1. Introduction

National Grid's health care plans are self-insured (Exh. NG-MPH-1, at 23). National Grid booked $18,946,518 in test year medical and dental costs (Exh. NG-RRP-2, at 11). Of that amount, MECo and Nantucket Electric directly incurred $8,450,973 in health care expense (Exh. DPU-8-2). NGSC and affiliated companies allocated $10,260,676 and $234,869 to the Company's test year medical and dental expense, respectively (Exh. DPU-8-2). The Company

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127 ($1,466,588 adjusted test year group insurance expense * 0.0541 percentage change in rate year O&M wages = $79,331) – $4,877 Company adjustment for management program = $74,455 final group insurance expense adjustment (see Exh. NG-RRP-2, at 12 (Rev. 3)).

128 $4,792,161 adjusted test year thrift expense * 0.0541 percentage change in rate year O&M wages = $259,221 final thrift expense adjustment (see Exh. NG-RRP-2, at 13 (Rev. 3)).

initially proposed a decrease to test year medical and dental expense of $250,830 based on 2016 working rates,[129] which also includes adjustments for five proposed Company positions and 36 proposed NGSC positions (Exhs. NG-RRP-1, at 29-30; NG-RRP-2, at 11). Based on revisions made during the proceeding, National Grid now proposes to decrease test year medical and dental expense by $263,968 (Exh. NG-RRP-2, at 11 (Rev. 3)). This change reflects a reduction to the total proposed Company positions from five to four, and a reduction to the total proposed NGSC positions from 36 to 33 (Exh. NG-RRP-2, at 11 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General's comments regarding medical and dental expense adjustments are specific to those made to include vacant positions and are addressed in Section VIII.A.4.b.i above (Exhs. AG-DJE-1, at 6-7; AG-DR-1, at 8; AG-DJE-Rebuttal-1, at 2-3; AG-DR-Rebuttal-1, at 4).

b. Company

National Grid argues that its medical and dental costs are reasonable in amount (Company Brief at 104). Further, the Company contends that the Towers Watson studies included in the initial filing illustrate that the health care plans offered to non-union and union employees are close to and above the market medians, respectively (Company Brief at 104, citing Exh. NG-MPH-1, at 22). Additionally, National Grid claims that it has taken several steps

[129] Working rates are Towers Watson's, the Company's healthcare consultant, estimates of plan costs for the upcoming plan year. The working rates are based on enrollment data, at least twelve months of historical claims experience, marketplace trends, plan design changes, compliance-related fees, and other relevant factors that impact the cost of claims to be paid by the Company (Exhs. DPU-8-5; AG-13-17; AG-13-17, Atts. 1-2).

to control its medical and dental expenses (Company Brief at 104). In particular, the Company describes cost containment steps such as self-insuring its health and welfare plans, obtaining a volume discount for its new prescription drug plan, periodically soliciting bids for alternative health care providers, and moving benefits administration to a new, third party to provide better service at lower costs (Company Brief at 104).

National Grid also argues that its proposed adjustment to test year health costs conforms to Department requirements (Company Brief at 107). The Company explains that its rate year level of medical and dental expense is based on the test year-end actual employee plan elections and associated individual plan cost rates that are in effect for calendar year 2016 (Company Brief at 108, citing Exhs. NG-MPG-1, at 26; AG-13-17). Further, National Grid explains that the individual plan cost rates, developed by its external benefits consultant, Towers Watson, are derived on the basis of current and historical information pertaining to National Grid's employee base, including past claims experience, administrative fees and other elements (Company Brief at 108, citing Exh. AG-13-17). The Company argues that the Department should rely on the working rates because they are developed using actuarial principles similar to the analysis formerly used to generate insurance premiums, which the Department accepts as the basis for post-test year changes in health care insurance costs (Company Brief at 109). The Company also contends that its decision to self-insure and use working rates that do not include additional costs present in insurance premiums produces substantial benefits for customers in the form of reduced benefit costs (Company Brief at 109). Finally, the Company claims that the Department has expressly recognized that the use of working rates to identify the representative level of costs on a post-test year basis is a reasonable method for the rate-setting process (Company Brief at 110,

citing D.P.U. 92-210, at 43-44; D.P.U. 95-40, at 22). Thus, the Company asserts that the Department should rely on the working rates (Company Brief at 108).

3. Analysis and Findings

To be included in rates, medical and dental insurance expenses must be reasonable. D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (1991). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. Berkshire Gas Company, D.T.E. 01-56, at 60 (2002); D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test year adjustments to health care expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

As an initial matter, the Department finds that National Grid's medical and dental insurance expenses are reasonable and that the Company has taken reasonable and effective measures to contain health care costs (Exhs. NG-MPH-1, at 22-25; NG-MPH-3, at 23-30; NG-MPH-10, at 24-31; DPU-8-11; DPU-8-13; DPU-8-14). For example, the Company disaggregated its prescription drug programs from each medical plan and replaced them entirely with a CVS Caremark plan, providing volume discounts (Exh. NG-MPH-1, at 24). Additionally, National Grid introduced generic step therapy to the CVS Caremark plan in order to lower prescription drug costs (Exh. NG-MPH-1, at 24). The Company also held a competitive bidding process for alternative health care providers in 2015 that produced a five percent reduction in administrative fees beginning in 2016 across all populations administered by Blue Cross Blue Shield of Massachusetts, the Company's current national medical vendor (Exh. DPU-8-14).

Turning to National Grid's proposed post-test year decrease in medical and dental expense, the Company maintains that the working rates provided by Towers Watson are developed similarly to the historical insurance premiums that the Department accepts as the basis for post-test year changes in health care insurance costs and therefore should be relied upon (Company Brief at 108-109). The Department has previously denied recovery of pro forma health care expenses based on working rates derived from actuarial estimates encompassing a broad based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 14-150, at 151; D.P.U. 13-90, at 94. In the current case, however, National Grid's working rates are derived using almost exclusively Company-specific data such as medical and prescription drug claims experience, enrollment figures, plan design details, administration costs, and fees (Exhs. DPU-13-10, Att.; DPU-28-1, Att.; DPU-28-2; DPU-28-3; Tr. 4, at 551-553; RR-AG-4; RR-AG-9; RR-AG-11). The Company's working rates rely in part on industry-wide "trend rates" and "margins" (Tr. 4, at 551-553; RR-DPU-20). The "trend rate" represents the expected annual increase in the average cost of medical services ("medical inflation") and is derived using historical gross cost experience from 467 employers including National Grid, other employers in the energy services sector, and general industry employers (Exh. DPU-28-2; RR-DPU-20). The "trend rate" is used to adjust National Grid's 2014 medical and prescription drug claims to 2016 dollars (Tr. 4, at 534-535; RR-AG-5). The "margin" is a load applied to the final working rates to account for fluctuations in claims and is derived by comparing National Grid's own claims experience to the market (Exh. DPU-28-2, at 2; Tr. 4, at 542 and 552). The "trend rate" and "margin" components both include Company data and would be included in rate year insurance cost calculations regardless of whether the Company chose to self-insure or rely on third-party

insurance carriers (Tr. 4, at 542). Based on the foregoing analysis, the Department finds that National Grid's working rates are sufficiently correlated with the Company's own experience (i.e., versus that of a broad based pool of insured entities) to warrant their use in determining the Company's health care expense in this proceeding.

Additionally, National Grid's decision to self-insure its medical and dental plans results in direct savings to ratepayers in the form of lower employee benefit costs (Tr. 4, at 523-524 and 542-543). The Department recognizes that disallowing National Grid's post-test year adjustments on the basis of working rates would provide a disincentive for companies to implement aggressive cost control measures, such as switching to self-insurance, when such measures otherwise would be deemed cost-effective. D.P.U. 95-40, at 26; D.P.U. 92-210, at 22. Therefore, the Department accepts the Company's proposed decrease to medical and dental expense of $263,968 (Exh. NG-RRP-2, at 11 (Rev. 3)).

In addition to National Grid's proposed medical and dental expense adjustment, the Department removes post-test year medical and dental expenses of $86,778 associated with 37 vacancies previously excluded from the Company's proposed cost of service in Section VIII.A.4.c.[130] Accordingly, the Department reduces the Company's proposed cost of service by $86,778.

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130 ($63,043 medical and dental costs for proposed Company vacancies * .5234 O&M percentage of base wages = $32,994) + ($415,448 medical and dental costs for proposed NGSC vacancies * .1920 percentage of NGSC salary expenses allocated to Company payroll expense * .6744 O&M percentage of base wages = $53,783) = $86,778 reduction to proposed Company medical and dental expense adjustment (see Exh. NG-RRP-2, at 11 (Rev. 3)).

D. Uncollectible Expense

1. Introduction

During the test year, National Grid booked $62,292,694 in bad debt expense (uncollectible expense) related to its total operations (Exh. NG-RRP-2, at 4, 5, 19 (Rev. 3)). The Company proposes to decrease its total bad debt expense by $44,676,591 over the test year level based on the application of a bad debt ratio of 1.23 percent to delivery service revenues to arrive at delivery-related bad expense of $17,616,103 (Exhs. NG-RRP-1, at 23; NG-RRP-2, at 19 (Rev. 3)).[131]

The Company calculated its delivery service related bad debt ratio by dividing its total delivery service net write-offs for the twelve-month periods ending on June 30, 2013, June 30, 2014, and June 30, 2015 of $46,996,526 by its total delivery service retail revenues for that same three-year period of $3,826,016,551 (Exh. NG-RRP-2, at 19 (Rev. 3)). This calculation results in a bad debt ratio of 1.23 percent (Exh. NG-RRP-2, at 19 (Rev. 3)). The Company then multiplied the bad debt ratio of 1.23 percent by test year normalized delivery service revenues of $1,434,137,931,[132] to arrive at a bad debt expense of $17,616,103 (Exh. NG-RRP-2, at 19 (Rev. 3)).[133] The resulting bad debt expense of $17,616,103 represents a decrease of

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131 The supply-related portion of the bad debt expense is recovered through basic service rates. Therefore, the bad debt ratio is applied to only the delivery service revenues.

132 In the calculation of delivery service revenues in its initial filing, the Company did not include the adjustments for the low-income discount (a $61,180,895 credit) and the net metering lost distribution revenues (a $23,760,587 credit) (RR-DPU-49 & Att.).

133 Any discrepancies in amounts are the result of rounding the bad debt ratio, which the Company computes using a floating decimal of 1.2283409 (see Exh. NG-RRP-2, at 19 (Rev. 3)).

$44,676,591 when compared to the Company's test year level of expense of $62,292,694 (Exh. NG-RRP-2, at 19 (Rev. 3)).

The Company also calculated a bad debt expense associated with the proposed revenue increase. The Company multiplied the bad debt ratio of 1.23 percent by its proposed revenue increase of $201,900,249, to arrive at a proposed bad debt adjustment of $2,480,023 (Exh. NG-RRP-2, at 2, 19 (Rev. 3)).

2. Positions of the Parties

The Company asserts that it has properly calculated its uncollectible expense adjustment consistent with the Department precedent (Company Brief at 54-55, citing D.P.U. 14-150, at 158; D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71). No other party addressed the Company's bad debt calculations on brief.

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt in their cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; Commonwealth Electric Company/Cambridge Electric Light Company, D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140 (1991). The Department has found that the use of the most recent three years of data available is appropriate in the calculation of bad debt expense. D.P.U. 96-50 (Phase I) at 71. A company's bad debt ratio is derived by dividing the three-year delivery service net writ-offs by the delivery service billed revenues for the same period. Western Massachusetts Electric Company, D.P.U. 84-25, at 113-114 (1984); D.P.U. 1720, at 27; Massachusetts-American Water Company, D.P.U. 1700, at 22 (1984). This bad debt ratio is then multiplied by test year delivery service billed revenues, adjusted for any distribution revenues

increase or decrease that is approved in the current rate case. See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71.

The Department has reviewed the Company's bad debt calculations, the materials supporting the calculations, and other related record evidence (Exhs. NG-RRP-1, at 23; NG-RRP-2, at 2, 4, 5, 19 (Rev. 3); WP-NG-RRP-12; AG-DJE-1, at 7-10 & Sch. DJE-2; NG-RRP-Rebuttal-1, at 37-39; AG-DJE-Rebuttal-1, at 3; DPU-12-8; DPU-12-9; DPU-12-10; AG-2-30; AG-14-8; Tr. 14, at 1574-1576; RR-DPU-49). The Department concludes that the method used by the Company to calculate its uncollectible expense adjustments is consistent with the Department precedent. D.P.U. 09-39, at 164; D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140. Therefore, the Department approves the application of the Company's delivery service related bad debt ratio of 1.23 percent, applied to test year delivery service revenues (Exh. NG-RRP-2, at 2, 19 (Rev. 3)).

As set forth above, application of the 1.23 percent bad debt ratio to the test year normalized delivery service revenues of $1,434,137,931, produces a bad debt expense of $17,616,103 (Exh. NG-RRP-2, at 19 (Rev. 3)). During the test year, the Company booked $62,292,694 in bad debt expense related to its total operations (Exh. NG-RRP-2, at 4, 5, 19 (Rev. 3)). Accordingly, the Department approves the Company's proposed decrease to its test year cost of service in the amount of $44,676,591.

Further, as set forth above, the Company calculated a bad debt expense of $2,480,023 associated with its proposed revenue increase (Exh. NG-RRP-2, at 2, 19 (Rev. 3)). Applying the same 1.23 percent bad debt ratio set forth above to the distribution revenue increase approved in

this case of $169,670,239 results in a bad debt expense in the amount of $2,084,129. Accordingly, the Department reduces the Company's proposed cost of service by $395,894.

E. Depreciation Expense

1. Introduction

During the test year, National Grid booked $123,025,248 in depreciation expense (Exh. NG-RRP-2, at 27 (Rev. 3)).[134] The Company proposes to increase its depreciation expense by $3,650,455 to $126,675,703, based on a "technical update" of the depreciation study provided in the Company's previous rate case, D.P.U. 09-39 ("2009 Depreciation Study") (Exhs. NG-RRP-2, at 27 (Rev. 3); NG-REW-1, at 3; NG-REW-2). The technical update results in a reduction in the Company's current composite depreciation accrual rate from 3.19 percent to 3.18 percent (Exh. NG-REW-2, at 36).

The Company's depreciation accrual rates include a provision for salvage (Exhs. NG-REW-1, at 7; NG-REW-2, at 5). When National Grid retires plant, the associated scrap materials are initially returned to crew barns, where they are then transferred to 40-foot containers (Tr. 2, at 212-213). These containers are periodically shipped to National Grid's investment recovery operation in Syracuse, New York, where the materials are processed and sold at auction, with the proceeds credited to standing retirement work in progress blanket work

134 This amount excludes $2,527,499 in depreciation expense associated with Nantucket Electric's submarine cables and $1,671,463 in depreciation expense associated with SmartGrid (Exh. NG-RRP-2, at 27 (Rev 3)). The Company excluded this depreciation expense because the cost of the Nantucket submarine cables and these SmartGrid expenses are recovered through separate mechanisms (Exhs. DPU-31-6; DPU-31-7).

orders[135] (Exh. AG-18-9; Tr. 2, at 213). In March of 2015, National Grid transferred to their respective plant accounts $26,225,351 in salvage that had been accumulated in MECo's blanket work orders between 2007 and March 2015 to their respective plant accounts (Exhs. AG-18-9; AG-30-1, Att.).

2. Company's Depreciation Technical Update

The Company did not perform a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past (Exh. NG-REW-1, at 3). Instead, the Company performed a technical update ("2015 Technical Update") of the 2009 Depreciation Study (Exhs. NG-REW-1, at 3; NG-REW-2). A technical update generally retains the parameters developed and/or approved in the most recent full depreciation study, and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates that have occurred over the passage of time (Exh. NG-REW-1, at 3). A technical update, therefore, is intended to align a company's depreciation rates with the accounting year during which the rates will become effective (Exh. NG-REW-1, at 3).

The 2009 Depreciation Study was based on plant data as of the end of the test year used in D.P.U. 09-39 (i.e., December 31, 2008), and employed the remaining life method (Exh. AG-3-40, at 19). Under the remaining life method, the net un-depreciated plant investment, net of salvage, is assigned through equal annual depreciation charges over the

135 Because of the limited amount of scrap materials generated by Nantucket Electric and prohibitive transport costs associated with ferrying containers off the island, scrap sales associated with Nantucket Electric are minimal (Exh. NG-DJD-Rebuttal-1, at 13; Tr. 2, at 220).

remaining estimated life of the property (Exh. AG-3-40, at 19). For most of its plant accounts, the Company uses the retirement rate method[136] to develop an average service life ("ASL") for each account by plotting life table data that were then fitted to Iowa-type survivor curves[137] to determine the appropriate survivor curve for these accounts[138] (Exh. NG-REW-1, at 6-7).

The steps involved in preparing a technical update generally include: (a) data collection; (b) calculation of service life statistics; (c) computation of average net salvage rates; (d) rebalancing of depreciation reserves; and (e) development of accrual rates (Exh. NG-REW-1, at 5). The Company explains that data was collected and applied by documenting plant accounting and depreciation reserve transactions from 2009 through 2014, and age distributions of surviving plant until December 31, 2014, which the Company's depreciation consultants then added to its 2009 Depreciation Study data (Exh. NG-REW-1, at 3). The Company matched accounting entries with transaction codes to identify and distinguish various types of plant accounting transactions (Exh. NG-REW-1, at 3-4).

The Company states that with the exception of certain general plant categories for which amortization accounting previously has been approved, the depreciation rates developed in the

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136 The retirement rate method is an actuarial method of deriving survivor curves based on the average rates at which property of each age group is retired by the Company over the period of time included in the depreciation study (Exh. NG-6, at 77).

137 Iowa curves are frequency distribution curves that were initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; these curves are widely accepted in determining average life frequencies for utility plant. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). Initially, 18 curve types were published in 1935; four additional survivor curves were identified in 1957. D.P.U. 09-39, at 168 n.106.

138 The ASL and Iowa curve are customarily reported as a combined figure; for example, a "75-R2.5" curve refers to an ASL of 75 years combined with an R2.5 Iowa curve.

2015 Technical Update were calculated using the straight line method, vintage group procedure, and remaining life techniques (Exh. NG-REW-1 at 7). The Company then developed composite life statistics for each required account (Exh. NG-REW-1, at 7).

3. Attorney General's Depreciation Analysis

The Attorney General challenges the underlying premises of the Company's proposed depreciation accrual rates. According to the Attorney General, National Grid's 2015 Technical Update was limited to updating various balances and salvage data, and that its failure to update projection curves, projection lives, future cost of removal and gross salvage rates resulted in accrual rates that are virtually identical to the Company's existing rates (Exh. AG-WDA-1, at 8-10).

The Attorney General identifies other deficiencies indicated by the 2015 Technical Update. First, the Attorney General contends that while the 2015 Technical Update indicates that National Grid's theoretical depreciation reserve[139] should be $1,492,421,587, the Company's salvage practices have resulted in a recorded depreciation reserve of $1,655,620,338, indicating a depreciation reserve surplus of $163,198,751 as of December 31, 2014[140] that continues to grow (Exhs. AG-WDA-1, at 8, 10, 13-15).

The Attorney General states that this surplus situation has been further exacerbated by the Company's failure to properly treat salvage (Exh. AG-WDA-1, at 10-15). The Attorney General

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139 The theoretical depreciation reserve represents the amount that should be in the depreciation reserve if the depreciation accrual rates presently in effect were to remain in use until all of that company's plant in service as of that date of the reserve calculation has been retired (Exh. AG-WDA-5, at 3; Tr. 13, at 1509).

140 The Attorney General adds that because of the Company's failure to properly record salvage, the depreciation reserve surplus was actually $189,048,306 as of that date (Exh. AG-WDA-1, at 10).

explains that while the USOA-Electric Companies requires that salvage be credited to the depreciation reserve, the Company accumulated salvage in blanket work orders for a number of years, and only credited the salvage on March 15, 2015, after the completion of the 2015 Technical Update (Exh. AG-WDA-1, at 4-7). The Attorney General states that if the Company had adhered to the salvage recording requirements of the USOA-Electric Companies, an additional $25,849,645 relating to salvage for the years 2007 through 2014 would have been credited to National Grid's depreciation reserve as of December 31, 2014 (Exh. AG-WDA-1, at 5-8).[141]

Further, the Attorney General notes that according to the National Association of Regulatory Utility Commissioners' Public Utility Depreciation Practices Manual (August 1996) ("NARUC Manual"), a utility should take immediate action to reduce depreciation imbalances, such as the implementation of revised depreciation accrual rates (Exh. AG-WDA-1, at 12, 16-18), Despite this obligation, however, the Attorney General estimates that under the Company's proposed accrual rates, it would take over 500 years to pass this surplus back to customers (Exh. AG-WDA-1, at 10-11),

Next, the Attorney General contests National Grid's proposed accrual rates. Specifically, the Attorney General notes that National Grid's proposed ASLs are, on average, shorter than the Department-approved ASLs currently in use by Western Massachusetts Electric Company ("WMECo") and NSTAR Electric Company ("NSTAR Electric") for most of the larger plant

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141 In her initial testimony, the Attorney General added the $25,849,645 surplus back to the Company's depreciation reserve to develop her proposed accrual rates (Exh. WDA-1, at 8; AG-WDA-3). On rebuttal testimony, the Attorney General determined that, given the complexities and relatively small dollar effects, no such adjustment was necessary, and thus revised her accrual rates accordingly (Exhs. AG-WDA-Rebuttal-1, at 4-5; AG-WDA-Rebuttal-2).

accounts (Exhs. AG-WDA-1, at 21; AG-WDA-4). The Attorney General performed an actuarial analysis for each Company plant account developing ASLs, Iowa curves, and salvage factors using the formulas and requirements for an actuarial analysis that are set forth in the NARUC Manual (Exhs. AG-WDA-34, at 9; AG-WDA-1, at 20-21; AG-WDA-4). Based on her analysis, the Attorney General calculated different accrual rates for 26 of the Company's 31 transmission, distribution, and depreciable general plant accounts (Exhs. AG-WDA-3, at 5, 9; AG-WDA-Rebuttal-2; AG-WDA-Rebuttal-3). These accrual rates produce a composite accrual rate of 2.77 percent versus the Company's proposed composite accrual rate of 3.18 percent (Exhs. AG-WDA-Rebuttal-1, at 4-5; AG-WDA-Rebuttal-2, at 2).

4. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General offers a number of recommendations concerning the Company's depreciation rates and practices (Attorney General Brief at 63-64). First, the Attorney General recommends that the Department require the Company to record salvage within 18 months of the retirement of its assets (Attorney General Brief at 63). Second, the Attorney General recommends that the Department adopt her depreciation accrual rates and reject the Company's 2015 Technical Update (Attorney General Brief at 63, citing Exhs. AG-WDA-1; AG-WDA-2; AG-WDA-3; AG-WDA-4; AG-WDA-Rebuttal-1; AG-WDA-Rebuttal-2). Finally, the Attorney General recommends that the Company's depreciation rates should be recalculated to account for retired plant that she contends had not been removed from National Grid's gross plant accounts (Attorney General Brief at 63-64).

ii. Salvage Accounting

The Attorney General argues that National Grid misrepresents its net rate base, that the Company has been doing so for several years, and has been commensurately over charging ratepayers (Attorney General Brief at 64). The Attorney General contends that from 2007 through 2014, National Grid failed to record $25,849,645 of salvage to its plant accounts at the time plant was retired, and instead allowed this balance to accumulate in retirement work in progress blanket work orders that had been kept open (Attorney General Brief at 65, citing Exhs. AG-18-9, AG-30-9). Further, the Attorney General claims that National Grid did not credit the accumulated salvage for those years to the depreciation reserve until March 31, 2015, as opposed to crediting salvage to the depreciation reserve when the assets were retired (Attorney General Brief at 65, citing Exh. NG-DJD-Rebuttal-1, at 4). In addition, she asserts that National Grid's failure to record salvage cannot be reasonably attributed to National Grid's SAP implementation issues because the Company had stopped recording salvage several years before the inception of the SAP project on November 5, 2012 (Attorney General Brief at 65-66, citing Exh. NG-MLK-1, at 29).

The Attorney General argues that National Grid's failure to properly record salvage violated the Department's accounting requirements (Attorney General Brief at 64-65; Attorney General Reply Brief at 46-47). More specifically, she contends that the Department requires electric distribution companies to maintain their books in accordance with the USOA-Electric Companies (Attorney General Brief at 65). According to the Attorney General, the USOA-Electric Companies requires that at the time depreciable utility plant is retired, the account shall be charged with both the book cost of the property being retired and the cost of

removal, and shall be credited with the salvage value and any other amounts recovered, such as insurance proceeds (Attorney General Brief at 65, citing 18 CFR Part 101, Account 108(B)).[142] Instead, the Attorney General alleges that the Company accumulated $25,849,645 of salvage in retirement work in progress blanket work orders from 2007 through 2014 that it kept open during this period (Attorney General Brief at 65, citing Exhs. NG-DJD-Rebuttal-1, at 4; AG-18-9; AG-30-9).

The Attorney General argues that the Company's violations of salvage accounting requirements had the effects of both inflating the Company's rate base and making it "impossible" to properly evaluate the Company's salvage rates used to derive its depreciation accrual rates (Attorney General Brief at 66, 69-70). According to the Attorney General, the Company's failure to record salvage in 2007 and 2008 attributable to MECo resulted in a rate base that was overstated by $4,992,994 (Attorney General Brief at 66, citing Exh. AG-30-1, Att. at 1). The Attorney General calculates that, based on the 7.85 percent overall rate of return granted to National Grid in D.P.U. 09-39, the Company has collected $391,950 in excessive returns during each of the years that the rates set by D.P.U. 09-39 have been in effect, thus producing an over-collection of over $2 million over the past six years (Attorney General Brief at 66-67). Moreover, the Attorney General points out that, because these dollars were included in base rates, the Department is "powerless" to return the money to customers due to the prohibition on retroactive ratemaking (Attorney General Brief at 67, citing Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. 625,

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142 The Attorney General points out that there is nothing in 220 C.M.R. § 51.02 or § 51.03 that modifies the USOA-Electric Companies' requirements regarding the recording of salvage (Attorney General Brief at 65).

637–38 (2004), citing Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 6 (1978)).

Further, the Attorney General argues that the Company's failure to properly record salvage has resulted in excessive charges being recovered through the CapEx mechanism (Attorney General Brief at 67).[143] Specifically, the Attorney General alleges that because the Company continued to withhold tens of millions of dollars in salvage since 2008 (the Company's test year in D.P.U. 09-39), this failure to properly record salvage would have caused the Company to overcharge customers in each and every year up to and including the 2014 reconciliation year in its CapEx dockets (Attorney General Brief at 67, citing Exh. AG-30-1, Att. 1).[144] However, the Attorney General asserts that because the CapEx is a reconciling mechanism, the Department can order retroactive adjustments and return these excess collections to ratepayers with interest (Attorney General Brief at 67, citing Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. at 637–38 (holding that the rule against retroactive ratemaking does not apply to rate mechanisms outside of base rates); Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 28 (2001)). Consequently, the Attorney General recommends that the Department open a proceeding to return the over-collection with interest to ratepayers (Attorney General Brief at 67).[145]

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143 As discussed in Section V above, the Company's CapEx mechanism is now known as the CIRM.

144 The Attorney General identifies the following CapEx dockets: D.P.U. 10-79 (2009); D.P.U. 11-60 (2010); D.P.U. 12-48 (2011); D.P.U. 13-84 (2012); D.P.U. 14-95 (2013); and D.P.U. 15-82 (2014) (Attorney General Brief at 67).

145 The Attorney General provides that in the alternative, if the Department elects to keep the Company's capital tracker, the Department could direct the Company to refund

Additionally, the Attorney General recommends that the Department direct National Grid, on a to going forward basis, to credit salvage amounts to the accumulated provision for depreciation as required by the USOA-Electric Companies, and record such salvage amounts to the data file that would be used in a depreciation study within 18 months of National Grid's selling any Company asset or otherwise accruing salvage (Attorney General Brief at 68-69).

Finally, the Attorney General recommends that the Department set National Grid's allowed return on common equity at the lowest end of the range of reasonability, as a result of the Company's alleged systematic failure to maintain its salvage records in accordance with Department requirements (Attorney General Brief at 67-68; Attorney General Reply Brief at 47). The Attorney General considers this reduction to be reasonable and appropriate, and asserts that it will prevent National Grid and other companies from engaging in practices that result in the misrepresentation of their rate base in the future (Attorney General Brief at 69).

iii. Depreciation Analysis

The Attorney General notes that National Grid relies on the same life-curves as those approved in D.P.U. 09-39 (Attorney General Brief at 70; Attorney General Reply Brief at 36). The Attorney General maintains that as a result of the Company's use of these life-curves, National Grid has proposed to use in most cases shorter depreciation lives that are appropriate (Attorney General Brief at 70; Attorney General Reply Brief at 36). The Attorney General asserts that the Department should lengthen the Company's proposed depreciation lives for a number of reasons.

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customers as part of its next capital investment report filing (Attorney General Brief at 67 n.26).

First, the Attorney General argues that the use of life curves will assist in remedying what she considers to be excess depreciation reserves. According to the Attorney General, the Company has a relatively large $163 million reserve surplus, a disparity that she maintains is growing and warrants immediate adjustment (Attorney General Brief at 70; Attorney General Reply Brief at 36, 40, citing Exh. NG-6, at 189). The Attorney General rejects the notion that when delayed retirements are included, the Company's pro forma excess reserve balance was only $77 million at the end of 2015 (Attorney General Reply Brief at 40-41). According to the Attorney General, the Company's reserve calculations fail to credit approximately $130 million in depreciation expense booked to both MECo's and Nantucket Electric's reserves for 2015 (Attorney General Reply Brief at 41, citing Exhs. NG-DJD-Rebuttal-2; AG-5; Tr. 2, at 202; Tr. 13, at 1486–1487). Thus, the Attorney General contends that had National Grid conducted its own analysis properly, factoring delayed retirements into the calculation actually suggests that the Company's depreciation reserve would have been $200 million, which is even higher than the surplus reported in its 2015 Technical Update (Attorney General Reply Brief at 41).

Second, the Attorney General argues that her proposed life curves fit the data better than those that the Company proposes to continue using (Attorney General Brief at 71). In this regard, the Attorney General contends that the Company's SAP implementation issues had no effect on her analysis of post-2008 data, because (1) the Company did not begin the SAP implementation process until late in 2012, and (2) her own sensitivity analyses demonstrates that, even if all of the data from the SAP implementation period were excluded, her recommended life curves still fit the data better than the Company's current life curves for all but one account (Attorney General Reply Brief at 37-38).

Third, the Attorney General points out that the Company's current ASLs are comparably shorter than those in effect for NSTAR Electric and WMECo (Attorney General Brief at 71; Attorney General Reply Brief at 36). The Attorney General argues that National Grid has failed to offer any evidence that a comparison of the Company to either NSTAR Electric or WMECo is inappropriate (Attorney General Reply Brief at 42).[146]

Finally, the Attorney General contends her depreciation witness is highly familiar with electric utility facilities, and was able to obtain all necessary information through the discovery process in order to analyze the Company's ASLs (Attorney General Reply Brief at 39-40). In this regard, she asserts that the Company's criticism that her witness failed to conduct a site visit of National Grid's facilities is without merit (Attorney General Reply Brief at 39).

Based on her analysis, the Attorney General proposes increased ASLs and different net salvage amounts for the Company's transmission and distribution plant accounts (Attorney General Brief at 71; Attorney General Reply Brief at 36). The Attorney General calculates that her recommended accrual rates produce a reduction of $15,937,950 in the Company's proposed annual depreciation expense (Attorney General Brief at 70, citing Exhs. AG-WDA-3-Rebuttal, at 2; NG-RRP-2, at 27.).

iv. Delayed Retirement

The Attorney General recommends that the Department adjust the Company's proposed depreciation expense for delayed retirements that are included in the Company's plant in service (Attorney General Brief at 82). According to the Attorney General, the Company concedes that

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146 By way of example, the Attorney General contends that there is no record evidence suggesting that National Grid's underground conduit can be expected to have a shorter life than underground conduit installed in the service territories of other Massachusetts electric distribution companies (Attorney General Reply Brief at 39).

it overstates its gross plant in service for the test year by amounts that actually should have been booked as retirements (Attorney General Brief at 82, citing Tr. 2, at 228; RR-AG-28). The Attorney General claims that the Company's delinquency in reporting delayed retirements in the year in which they occurred is specifically prohibited by FERC and Department regulations (Attorney General Reply Brief at 45-46).[147] The Attorney General recommends that the Department set the Company's ROE at the lowest end of the range of reasonableness for its purported misrepresentation of gross and net plant resulting from delayed retirements (Attorney General Reply Brief at 46-47).

Further, the Attorney General recognizes that when National Grid retires plant booked to Account 101, it appropriately makes a corresponding adjustment to the accumulated depreciation reserve in Account 108, thus producing a rate base-neutral outcome (Attorney General Reply Brief at 43 n.14). Despite this rate base neutrality, however, the Attorney General points out that because depreciation expense is calculated based on gross plant in service and not net rate base, debits entries to Account 108 do not make the delayed retirements revenue neutral in terms of depreciation expense (Attorney General Reply Brief at 43). The Attorney General notes that while National Grid is correct in that delayed retirements should not trigger a rate base adjustment, the Company does not dispute that a commensurate accounting of depreciation expense is required (Attorney General Reply Brief at 43, citing Company Brief at 160).

In her initial brief, the Attorney General proposed to calculate the depreciation expense adjustment by multiplying her recommended composite depreciation accrual rate of 2.77 percent

147 The Company defines asset unitization as the process by which the charges accumulated in the completed construction not classified account at a gross level are classified by accounts and retirement units (Exh. NG-DJD-Rebuttal-1, at 10).

by $107,400,000 in gross plant, producing an adjustment of $2,974,980 (Attorney General Brief at 84-85). On her reply brief, the Attorney General accepted the Company's proposal to calculate the adjustment by multiplying a composite depreciation accrual rate by $52,697,141 in plant that actually had been physically retired prior to the end of the test year, but remained recorded on the books after June 30, 2015 (Attorney General Reply Brief at 43). Based on her proposed depreciation accrual rates, the Attorney General calculates an adjustment of $1,459,711 under this approach[148] (Attorney General Reply Brief at 43).

b. Company

i. Introduction

National Grid defends its decision to confine its depreciation analysis in this proceeding to its 2015 Technical Update (Company Reply Brief at 55-56). According to National Grid, the SAP stabilization process occurred from November 2012 to September 2014 (Company Reply Brief at 56). The Company argues that the stabilization process resulted in what it considered to be "unavoidable" disruptions in the processing of plant transactions and that these disruptions could have affected retirement and net salvage data recorded during this period, and, therefore, would have adversely affected the Company's ability to estimate projection curves, projection lives, and future net salvage rates (Company Reply Brief at 56, citing Exhs. NG-MLR-1, at 26-29; AG-3-1). Thus, the Company asserts that under these conditions, a full depreciation study using plant data documented before the SAP stabilization would have taken considerable time and effort to conduct, and had the potential to produce results that were unreliable and inconsistent with reasonable utility practice (Company Reply Brief at 56, citing Exh. AG-3-1,

[148] $52,697,141 * 2.77 percent = $1,459,711.

at 2). As such, the Company concludes that although under normal circumstances a full depreciation study would have been warranted, in this case, a technical update could support the analysis required for calculating depreciation expense, with the 2009 Depreciation Study being used for limited support (Company Reply Brief at 56).

ii. Salvage Accounting

National Grid argues that the Attorney General's recommendations concerning the crediting of salvage to accumulated depreciation are unnecessary (Company Brief at 157). According to the Company, after it first experienced SAP implementation issues, National Grid encountered delays in processing plant transactions, such as asset unitization and retirements (Company Brief at 157-158, citing Exhs. NG-DJD-Rebuttal-1, at 5; AG-29-4). The Company argues that even after the SAP system was stabilized, there was a backlog of transactions to be processed that caused a delay in recording salvage, as well as the need to resolve conversion, data, and mapping errors that had occurred (Company Brief at 157-158, citing Exh. NG-DJD-Rebuttal-1, at 6). The Company contends that had the retirements and associated cost of removal pertaining to work orders placed in service prior to December 31, 2014 been accounted for in the proper period, rather than through a retrospective correction, the pro-forma excess reserve would be approximately $77 million, an imbalance that National Grid represents as being within the ten-percent deviation that is acceptable in the utility industry (Company Brief at 159, citing Exh. NG-DJD-Rebuttal-1, at 12; Tr. 2, at 239).

Moreover, the Company attributes delays in unitizing the salvage proceeds associated with blanket work orders to the logistical challenge associated with classifying physical containers full of scrap materials generated from capital work orders for identification and

disaggregation into their respective FERC accounts (Company Brief at 156, citing Exh. NG-DJD-Rebuttal-1, at 10-11). National Grid maintains that it currently is not experiencing any undue delays in recording salvage due to SAP implementation issues, and considers there to be no need for an "arbitrary" 18-month requirement, particularly for situations where reasonable delays can occur in recording all transactions associated with asset retirements (Company Brief at 158).

Additionally, the Company denies the Attorney General's assertion that net rate base in any year 2007 through 2015 was overstated for ratemaking purposes (Company Brief at 155-156, citing Exh. AG-WDA-Rebuttal-1, at 4).[149] The Company contends that the delays cited by the Attorney General were primarily due to the delays in processing salvage material as noted above, and that such delays did not purposefully distort its net rate base or erroneously postpone booking salvage for the period of 2007 through 2014 (Company Brief at 155). As such, the Company argues that the Attorney General's assertions on this point should be disregarded (Company Brief at 156).

The Company also contends that the Attorney General's assertions regarding over-collection through the CapEx are groundless, because total plant additions and cost of removal surpassed the $170 million cap each year from 2009 through 2015 (Company Brief at 155, citing RR-DPU-13). The Company asserts that the annual accumulations totaling $25,849,645 of salvage would not have altered recovery under the CapEx in any one year (Company Brief at 155, citing RR-DPU-13). Thus, the Company rejects any notion that it

[149] National Grid asserts that the Attorney General's depreciation witness made no further mention of the Attorney General's allegations of an overstated rate base once the Company demonstrated that the witness's proposed adjustment was actually one-sided (Company Brief at 155-156).

"overstated" its net rate base in both D.P.U. 09-39 and its annual CapEx filings, and over-collected more than $2 million during the period in question through base rates and the CapEx (Company Brief at 155-157). For these reasons, National Grid argues that the Attorney General's recommendation to decrease the Company's ROE is baseless (Company Brief at 155).

iii. Depreciation Analysis

National Grid submits that it is not proposing to change the ASLs and survivor curves approved in its last rate case, D.P.U. 09-39 (Company Brief at 152, citing Exhs. NG-REW-1, at 4; NG-REW-2, at 17-18; AG-3-1). The Company asserts that its survivor curves were estimated in the 2009 Depreciation Study from a statistical analysis of past retirement experience along with forecasting for future changes (Company Brief at 152, citing Exh. NG-REW-1, at 4-5). The Company notes that beginning with its 2009 Depreciation Study, it next recorded statistics for each vintage in its technical update to account for known and measurable changes in the age distributions of surviving plant from December 31, 2008 through December 31, 2014 (Company Brief at 152, citing Exh. NG-REW-1, at 5).

The Company questions the Attorney General's proposed longer survivor curves, and denies the assertion that the Attorney General's curves have a statistically superior fit and that the reserve balance is increasing (Company Brief at 158, citing Attorney General Brief at 70-71). Rather, National Grid argues that the Attorney General's proposed ASL curves are faulty because they are based on inadequate historical data from 2009 and 2014, which was the result of the Company's SAP implementation issues (Company Brief at 158, citing Exh. AG 3-1).

iv. Delayed Retirement

The Company disputes the level of the Attorney General's proposed depreciation expense calculation (Company Brief at 160-161). National Grid contends that when it retires plant booked to Account 101, it appropriately makes a corresponding adjustment to the accumulated depreciation reserve in Account 108, which produces a rate base-neutral outcome and obviates the need for any rate base adjustment (Company Brief at 160). Moreover, the Company contends that the Attorney General's claimed $107,400,000 in retired plant actually includes $56,682,851 in plant that had been retired prior to December 31, 2014, but recorded on the Company's books prior to the end of the test year, and thus not recorded in the test year-end balance of gross plant (Company Brief at 161, citing RR-AG-28). Based on its determination that $52,697,141 in retirements was still on the Company's books as of the end of the test year, the Company considers that a depreciation expense adjustment of $1,675,769 would be warranted (Company Brief at 161).

5. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1983). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a company reaches a conclusion about a depreciation study that is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent

sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[150] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing, and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of statistical analyses, but will consider other expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase I) at 54-55. To the extent a depreciation study provides a

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150 Subjectivity is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

b. Salvage Accounting

The USOA-Electric Companies specifies that salvage shall be charged or credited, as appropriate, to the depreciation reserve. 18 CFR Part 101, Electric Plant Instructions, § 10(B)(2), Account 108; 220 C.M.R. § 51.01. There is no specific time limit beyond a requirement that proper distributions be made upon the completion of a work order. 18 CFR Part 101, Electric Plant Instructions, § 10(B)(2), Account 108; 220 C.M.R. § 51.01.

While National Grid objects to the Attorney General's proposal that salvage be credited within 18 months, the Company recently has instituted measures intended to improve its recording of salvage. Until recently, it was not possible for the Company's investment recovery staff to develop engineering estimates that would allow scrap material to be unitized by FERC plant account (Tr. 2, at 215). The Company has now implemented a process wherein the plant accounting department and investment recovery staff will collaborate to generate engineering estimates to support the unitization of scrap metal proceeds associated with standing blanket work orders (Exh. NG-DJD-Rebuttal-1, at 13; Tr. 2, at 215, 234). The Company represents that this procedure will provide sufficient salvage data to conduct depreciation study analysis at least annually (Exh. NG-DJD-Rebuttal-1, at 13). The Department expects that National Grid's new unitization procedure will allow the Company to complete the salvage recording process well within the 18 months proposed by the Attorney General. We are aware that there may be situations where salvage may remain in a blanket work order for a longer period of time, but we expect that those situations will be relatively rare. Based on the foregoing analysis, the

Department finds that 18 months represents a reasonable period for National Grid to complete the recording of salvage. While we do not mandate the imposition of an 18-month turnaround period at this time, we expect the Company to take reasonable measures to achieve this 18-month objective.

The Company and Attorney General have raised issues concerning depreciation reserve balances, and their effect on both base rates and the CapEx. By their very nature, depreciation accruals are imprecise because they attempt to evaluate the effect of innumerable factors on a particular asset over the useful life of that asset, a process that is necessarily wrought with uncertainty and requires constant review and modification. D.P.U. 12-25, at 308; D.P.U. 200, at 20; Boston Gas Company, D.P.U. 19470, at 48-49 (1978). Consequently, a utility may have shortfalls or surpluses in its depreciation reserve. In the absence of evidence of mismanagement of a company's depreciation accrual rates, the Department will not substitute its own judgment for that of management. D.P.U. 12-25, at 90; Barnstable Water Company, D.P.U. 93-223-B at 6-7 (1994); D.P.U. 19470, at 49-50. Cf. Wannacomet Water Company, D.P.U. 13525 (1962) (company continued to use inadequate depreciation accrual rates even after Department directed corrective action, resulting in depreciation shortfall of 115 percent).

The 2015 Technical Update indicates a theoretical depreciation reserve of $1,492,421,587 as of December 31, 2014, versus a booked depreciation reserve of $1,655,620,338 as of that same date (Exh. NG-REW-2, at 40). While the Attorney General and Company each advocate various adjustments associated with retirements and cost of removal through June 30, 2015, even using the numbers offering the most favorable light to the Attorney General's position, the depreciation reserve surplus would be $189,348,096, representing 12.66

percent of the theoretical reserve provided in the 2015 Technical Update (Exh. NG-DJD-Rebuttal-2). The Department does not consider this depreciation reserve imbalance to be so excessive as to warrant corrective measures. D.P.U. 93-223-B at 5, 6-7 (no adjustment for depreciation reserve shortfall of 11.38 percent).[151] To the extent that National Grid's new salvage recording procedures produce a more accurate depiction of the role salvage plays in the development of National Grid's depreciation reserve and depreciation accrual rates, these improvements will be incorporated in the Company's next depreciation study.

Based on these considerations, the Department finds that the Company's salvage practices have not resulted in an overstatement of its rate base. The Department further finds that the Company's salvage practices have not resulted in an over-recovery of costs through the CapEx component. Accordingly, the Department declines to make any adjustment to the Company's ROE for its salvage recording practices. The Department directs National Grid to conduct a full depreciation study in conjunction with its next base rate case, and to provide that study as part of its initial filing in that case.

c. Depreciation Analysis

National Grid relies on the 2015 Technical Update as the basis for its proposed accrual rates. As described above, a technical update generally retains the parameters developed and/or approved in a company's most recent full depreciation study, and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates that have occurred since the period covered by the full depreciation

151 Even at the $200 million depreciation reserve surplus claimed by the Attorney General on brief, the surplus would represent only 13.4 percent of the 2015 Technical Update's theoretical reserve.

study (Exh. NG REW-1, at 3). The Department has accepted the use of technical updates in lieu of a full analysis. See D.P.U. 95-118, at 159-161 (Department accepted technical update of cost allocation study originally based on 1989 data). In this case, however, a number of difficulties have been identified, particularly with respect to the recording of salvage. While the Department is persuaded that the Company's salvage recording practices have not resulted in excessive depreciation surpluses, we find that National Grid's salvage and retirement recording practices are such as to raise questions as to the validity of the 2015 Technical Update. Given these concerns, the Department finds that the 2015 Technical Update does not provide sufficient basis on which to revise National Grid's depreciation accrual rates. Therefore, the Department will not use the results of the 2015 Technical Update to determine the Company's depreciation accrual rates.

Turning to the Attorney General's depreciation analysis, the Company raises a number of concerns as to its reliability. First, National Grid challenges the Attorney General's consultant for his failure to conduct a site visit of the Company's facilities. As noted above, depreciation studies rely not only on statistical analysis, but also on the judgment and expertise of the preparer. Because depreciation studies involve consideration of a company's physical assets, the Department has emphasized the importance of a physical inspection of plant assets when conducting a depreciation study. D.P.U. 19037/19037-A at 23; see also D.T.E. 05-27, at 257-258. The Attorney General's consultant obtained what he considered to be all of the necessary information from Company management through discovery, supplemented by his familiarity with other electric distribution facilities (Tr. 13, at 1446-1448). While the Department recognizes that the Attorney General conducted extensive discovery on the issue of

depreciation, a site visit would have provided additional information that could have put the Company's written responses into perspective. At the very least, a site visit would have assisted in confirming the Company's responses to the witness through his own observations.

National Grid also challenges the Attorney General's comparison of the Company's ASLs with those of other Massachusetts utilities. While the Attorney General emphasized the dissimilarities of National Grid's ASLs to those of NSTAR Electric and WMECo, she did not demonstrate a significant level of familiarity with the latter two companies (Tr. 14, at 1467-1469). While different companies may have generally similar depreciation accrual rates, a greater familiarity with the characteristics of companies being used as comparisons to the company under examination will assist in identifying differing physical characteristics that may have an effect on depreciable lives and salvage factors.

Further, the Attorney General's analysis relies heavily on historical data from 2009 through 2014 (Exh. AG-WDA-9). Because of the implementation issues the Company experienced during the SAP implementation process, there were unavoidable disruptions in the processing of plant transactions (Exh. AG-3-1). These system disruptions could have affected retirement and net salvage data recorded during this period, and thus affected the statistical analyses required to estimate projection curves, projection lives, and future net salvage rates (Exh. AG-3-1).

More significantly, the Company's salvage and retirements recording practices resulted in the lack of sufficient data to develop a full depreciation study. During the first six months of calendar year 2015 (January 1, 2015 through June 30, 2015), the Company recorded approximately $56.7 million of retirements related to plant placed in service over the years prior

to December 31, 2014 (RR-AG-28). While this amount was recorded prior to the test year end and is appropriately recognized in this proceeding, these retirements were not included in the Company's December 31, 2014 plant balances, the point in time used by both the Company and Attorney General for the depreciation database (RR-AG-28, at 2-3). In addition, $50,695,664 in retirements associated with plant placed into service prior to December 31, 2014 was recorded by the Company after the end of the test year, June 30, 2015 (RR-AG-28). Had this information been fully accounted for, it is likely that a more reliable depreciation analysis could have been completed.

Finally, the Attorney General's analysis is largely confined to analysis of the Company's historic database, including partial retirement data through December 31, 2014 (Tr. 13, at 1446-1447). The Attorney General's analysis does not identify any physical changes in property attributable to retirement forces acting outside of the historical data (Tr. 13, at 1447). Although the Department has recognized that consideration of polynomials, conformance indices or hazard rates, can support the robustness of a depreciation study, the Attorney General's analysis does not take these factors into consideration (Exh. AG-WDA-2). See D.P.U. 15-81/D.P.U. 15-81, at 198 n.144; D.P.U. 09-39, at 183-190. Based on the foregoing analysis, the Department finds that the Attorney General's depreciation analysis does not provide a sufficient basis on which to revise National Grid's depreciation accrual rates.

In the absence of an acceptable depreciation study from either party, the Department has relied on the use of a company's then-current depreciation accrual rates. D.P.U. 13-75, at 216; D.P.U. 10-114; D.P.U. 243, at 17. In this case, the Department has rejected the use of both the Company's 2015 Technical Update and the Attorney General's depreciation study. Therefore,

the Department finds it appropriate to maintain the use of the Company's current depreciation accrual rates as derived in the 2009 Depreciation Study, and as modified in D.P.U. 09-39. The Department's calculation of the Company's depreciation expense is provided below.

d. Delayed Retirement

In order to derive a company's depreciation expense, depreciation accrual rates are applied to a company's gross depreciable plant in service. D.P.U. 14-150, at 199; D.P.U. 12-25, at 323. Both National Grid and the Attorney General agree that the Company's test year-end plant in service accounts include $52,697,141 in retirements that had been made prior to the end of the test year, but nonetheless remained in the Company's plant investment accounts (Company Brief at 161; Attorney General Reply Brief at 43). This error has no effect on the Company's rate base because when plant is retired, a corresponding entry is credited against the depreciation reserve. 18 CFR Part 101, Electric Plant Instructions, § 10(B); 220 C.M.R. § 51.01. Nonetheless, both parties agree that because depreciation expense is calculated on the basis of gross (versus depreciated) plant, an adjustment to depreciation expense remains warranted. Because this plant has been retired, the Department finds it appropriate to exclude any depreciation expense on these assets from cost of service. D.P.U. 14-120, at 36-37; Hutchinson Water Company, D.P.U. 85-194, at 7, 13 (1986).

The Company proposes to decrease depreciation expense by $1,675,769 (Company Brief at 161).[152] This adjustment appears to represent the $52,697,141 in retired plant multiplied by the Company's proposed composite depreciation accrual rate of 3.18 percent. The Attorney

[152] Examination of National Grid's revised revenue requirement schedules indicates that this adjustment has not been incorporated into the Company's revenue requirement calculations (Exhs. NG-RRP-2, at 5, 27 (Rev. 3); NG-RRP-8 (Rev. 3)).

General proposes to decrease depreciation expense by $1,459,711, which she derived by multiplying the $52,697,141 in retired plant by her proposed composite depreciation accrual rate of 2.77 percent (Attorney General Reply Brief at 43). In the absence of detailed plant accounts associated with these retired assets, the Department finds that the use of a composite depreciation accrual rate produces a reasonable level of depreciation expense associated with these retirements.

Neither the Company's nor the Attorney General's selected composite rates, however, had been in use at the time of these plant retirements. The Company's current depreciation accrual rates had been in effect at the time of the retirements; applying these rates to the December 31, 2014 plant balances used as the basis of the parties' depreciation calculations produce a composite accrual rate of 3.19 percent (Exh. NG-REW-1, at 9). On this basis, the Department finds it appropriate to base the depreciation adjustment on a composite depreciation accrual rate of 3.19 percent.

The $52,697,141 in retired plant, multiplied by a composite depreciation accrual rate of 3.19 percent, produces a depreciation expense associated with delayed retirements of $1,680,847. Accordingly, the Department reduces the Company's proposed depreciation expense by $1,680,847 for delayed retirements. Because the Company has made the necessary accounting adjustments to recognize the delayed retirements, the Department declines to make any adjustment to the Company's ROE related to delayed retirements.

e. Conclusion

In order to calculate National Grid's annual depreciation expense, the Department has applied the accrual rates approved by this Order to the Company's depreciable plant balances

included in rate base.[153] Based on this analysis, the Department calculates an annual depreciation expense, excluding depreciation associated with SmartGrid investments and Nantucket Electric's undersea cables, of $126,925,161 (Exh. NG-RRP-2, at 27 (Rev. 3)). Excluding the $1,680,847 in depreciation expense associated with unrecorded plant retirements produces a net overall depreciation expense of $125,244,314. This net overall depreciation expense represents an increase of $2,219,066 to the Company's test year depreciation expense, excluding that associated with SmartGrid investments and Nantucket Electric's undersea cables, of $123,025,248. National Grid has proposed an increase of $3,650,455 to its test year depreciation expense. Accordingly, the Department reduces the Company's proposed depreciation expense by $1,431,389.

F. Postage Expense

1. Introduction

During the test year, MECo booked $6,595,462 in postage expense (Exh. AG-1-34, Att. 6, at 17). The Company did not propose any adjustments to its test year postage expense, and thus included postage expense in the balance of test year O&M expenses subject to inflation ("residual O&M expense") component used to derive the inflation allowance (see Exh. NG-RRP-2, at 5-6, 23 (Rev. 3); Tr. 8, at 1358-1359).

153 For Accounts 392 (Transportation Equipment) and 396 (Power Operated Equipment), the Department applied a 6.67 percent amortization rate based on the 15-year amortization of general plant currently in use (Exh. NG-REW-2, at 46).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to recognize that the United States Postal Service ("USPS") postage rates are decreasing, and proposes that the Department reduce the Company's proposed cost of service to eliminate the postage surcharge that was in effect during the test year (Attorney General Brief at 58). The Attorney General contends that the Postal Regulatory Commission ordered the USPS to remove a 4.3 percent exigent surcharge once it had collected $4.6 billion in surcharge revenues, which was expected to occur by April 10, 2016 (Attorney General Brief at 58, citing Exh. AG-14). The Attorney General asserts that the Company's test year cost of service should thus be reduced by $283,605,[154] in order to eliminate the now-terminated postage surcharge from postage expense (Attorney General Brief at 58).

Further, the Attorney General claims that National Grid has overstated its postage expense because the Company includes postage expense in its residual O&M expense (Attorney General Brief at 58). Thus, the Attorney General argues that the Company's residual O&M expense must be reduced by $6,595,462 to recognize that postage expense has been specifically adjusted in the cost of service (Attorney General Brief at 58).

b. Company

National Grid agrees with the Attorney General's recommendation to reduce test year postage expense by $283,605 in order to account for the elimination of the USPS's exigent surcharge of 4.3 percent (Company Brief at 75). The Company also agrees to reduce its residual O&M expense by $283,605 (Company Brief at 76). However, National Grid opposes the

[154] $6,595,462 x 0.043 = $283,605

Attorney General's proposal to exclude the remaining $6,311,857 in test year postage expenses from the residual O&M expense, because it maintains that postage rates are likely to experience inflationary pressures (Company Brief at 76).

The Company argues that the expiration of the exigent surcharge was the result of a regulatory directive to the USPS, rather than the product of reduced postal service operating costs, and it further notes that USPS rates are capped by law at the rate of inflation (Company Brief at 75, citing Exh. AG-14). Thus, National Grid contends that the Attorney General unreasonably assumes that USPS services are not subject to inflation, or that there will be no postage rate increases in the future to counteract, or mitigate, the termination of the exigent surcharge (Company Brief at 75). The Company asserts that given the "significant" strain that the elimination of the 4.3 percent surcharge will have on the USPS, the only reasonable conclusion is that postage rates will increase at the rate of inflation in the near future (Company Brief at 76). Therefore, the Company states that its adjusted postage expense should be included in the residual O&M expense (Company Brief at 76).

3. Analysis and Findings

The Department recognizes postage expense as a legitimate cost of doing business. If a postal rate increase – or, in this case, a decrease - occurs prior to the issue of an Order, that resulting rate fluctuation is eligible for inclusion in cost of service as a known and measurable change to test year expense. D.P.U. 14-150, at 206; D.P.U. 10-55, at 286; D.P.U. 08-35, at 108; D.T.E. 05-27, at 194; D.P.U. 88-172, at 23-24; Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982). The elimination of the USPS' 4.3 percent exigent surcharge already has occurred and is quantifiable, and, therefore it is a known and measurable change (Exh. AG-14).

Accordingly, the Department accepts the proposed reduction of $283,605 to test year postage expense.

Turning to the remaining $6,311,857 in postage expense that National Grid seeks to retain in the residual O&M expense, the Company's argument that postage rates could increase in the near future due to inflationary pressures or due to the expiration of the exigent surcharge fails to recognize that postage rate changes are not subject to the same general pressure of inflation. While postage increases may be capped at the level of inflation, such increases are not automatic, but rather result from actions by the Postal Regulatory Commission. D.P.U. 1720, at 21-22. Consequently, future postage rate changes are not known and measurable. Accordingly, the Department rejects the Company's proposal to include postage expense in the residual O&M expense. Therefore, the Department will remove the full test year postage expense of $6,595,462 from the Company's residual O&M expense. The effect of this adjustment is shown on Table 1 of this Order.

G. Property Tax Expense

1. Introduction

During the test year, the Company booked $56,944,818 in property tax expense (Exhs. NG-RRP-1, at 2; NG-RRP-2, at 28 (Rev.3)). National Grid seeks to increase this amount by $2,331,371 to reflect the expected level of property taxes in the rate year (Exhs. NG-RRP-1, at 38; NG-RRP-2, at 28 (Rev. 3)). The Company calculated the estimated rate year level of property tax expense by applying current municipal tax rates to the latest property valuations provided by the Company to each municipality (Exhs. NG-RRP-1 at 38, NG-RRP-2, at 28

(Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-22-3).[155] The Company excluded from its proposed property tax expense third-party reimbursements associated with the rate year estimated figure, estimated Smart Grid-related property taxes, and property taxes related to construction work in progress ("CWIP") (Exhs. NG-RRP-1, at 39; NG-RRP-2, at 28 (Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-31-11; DPU-31-12; DPU-31-13).[156]

2. Positions of the Parties

National Grid argues that its proposed municipal property tax expense is calculated in a manner that is consistent with Department precedent, as the proposed expense is based on the most recent property tax bills that the Company received from the various municipalities in which it owns property (Company Brief at 92, citing D.T.E. 02-24/25 at 123; D.P.U. 96-50, at 109). The Company notes that it calculated the proposed adjustment beginning with an adjusted test year municipal tax expense of $56,944,818, and then calculated the estimated rate year level by applying current municipality tax rates to the latest property valuations provided by each municipality (Company Brief at 92, citing Exhs. NG-RRP-1, at 38, NG-RRP-2, at 28 (Rev. 2)). No other party addressed the Company's proposed property tax expense on brief.

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155 For those communities that rely on the Reproduction Cost New Less Depreciation method (see Section IX below) to determine property valuations, the Company estimated the assessed values by first determining the percentage by which the assessed value exceeded the net book value of the Company's personal property in that community for the previous tax year, and then multiplying that percentage by the net book value of the personal property in that community for the current tax year (Exhs. NG-RRP-1, at 38-39; DPU-22-3).

156 The Company received third-party reimbursements from Lightower, a former affiliate of MECo (Exh. DPU-22-11). National Grid pays property taxes on Lightower assets that are attached to the Company's poles, and Lightower reimburses the Company for the property taxes on those assets (Exh. DPU-22-11).

3. Analysis and Findings

The Department's general policy is to base pro forma level of property taxes that should be included in the revenue requirement on the most recent property tax bills from communities in which it has property. D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 14-150, at 209; D.P.U. 12-25, at 330; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). The Department holds the record open in a proceeding to receive from the utility the most current tax bills issued by cities and towns. D.P.U. 14-150, at 209; D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

The Company proposes to base its property tax expense on current tax assessments and tax rates, increased by a projection of future increases (Exhs. NG-RRP-1, at 38-39; NG-RRP-2, at 28 (Rev. 3); WP-NG-RRP-17 (Rev. 3); DPU-22-3). The Department generally has rejected the use of projected data to determine a company's property tax expenses. D.P.U. 14-150, at 209-210; D.P.U. 11-01/D.P.U. 11-02, at 280-281; D.P.U. 10-114, at 263; D.P.U. 09-39, at 244; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 109-110. Rather, the test year level of property tax expense, adjusted for known and measurable changes (i.e., the most recent property tax bills provided at the close of the record), provides the most reasonable representation of a company's property tax expense and fairly represents this component of its cost to provide service.[157] National Grid's projection of future increases of property tax expense, though derived

[157] In certain cases, such as where no property tax bills have yet been issued for a large post-test year plant addition that is being placed into service near the issue date of the Department's Order, the Department has allowed the associated property taxes to be based on the cost of the plant multiplied by the most recent property tax rate. D.P.U. 12-86, at 243-245; D.P.U. 95-118, at 148. That fact situation does not apply here. Further, the Department notes that in D.P.U. 13-75 and D.P.U. 12-25, it appears from the records that the subject company derived its post-test year property tax expense

from current tax assessments, is speculative and does not constitute a known and measurable change based on Department precedent. The Company has offered no persuasive reason to depart from our precedent here. Therefore, we decline to adopt the Company's proposed property tax calculation.

Based on the Company's most recent property valuations and actual property tax rates, National Grid's current property taxes payable to municipalities, fire districts, and water districts total $61,548,504 (Exh. DPU-22-4 & Atts.). The Department accepts this amount as known and measurable. The Department excludes from this total the property taxes associated with Lightower, Smart Grid and CWIP in the amount of $2,516,346 (Exh. NG-RRP-2, at 28 (Rev. 3)). Thus, the Company's final property tax expense is $59,032,158, which represents an increase over the test year amount of $2,087,340. The Company proposed to increase the test year amount of property tax expense by $2,331,371. Accordingly, we will reduce the Company's proposed cost of service by $244,031 ($2,331,371 minus $2,087,340).

Finally, we recognize that the recovery of property taxes is an important element of a company's operations. In addition to recovering a representative level of property tax expense through base rates, companies have proposed cost recovery mechanisms to address changes in property tax levels that occur between rate cases. For example, the Department has examined proposals to establish property tax recovery mechanisms outside of base rates to address fluctuations associated with the change in property valuation method used by municipalities.

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adjustment based on a composite rate formula. However, neither Order discusses the reasons for this treatment or contains a justification for the departure from the Department's otherwise long-standing precedent. We find that there was no express intention on the Department's part to change its long-standing precedent on property tax expense and, therefore, neither case is dispositive of our treatment of the matter here.

D.P.U. 14-150, at 269-282; D.P.U. 12-25, at 324-334 (see also Section IX below). We also have examined proposals to include the recovery of property taxes as part of a capital investment recovery tracker. D.P.U. 15-80/D.P.U. 15-81, at 54-55 (see also Section V.D.4 above). The Department acknowledges that, with the exception of application for abatements where warranted, property taxes are largely outside of a company's control. We also recognize that a consistent ratemaking approach to property taxes may increase efficiencies and reduce administrative burdens.

Given these considerations, the Department will consider whether it is appropriate to explore alternative ratemaking proposals from distribution companies to address property tax changes between rate cases. Without prejudging the question of the propriety of any alternative ratemaking proposal, a company must demonstrate in its proposal that there would be no double recovery of property tax expense. The Department will consider such proposals in the context of an individual company's base rate proceeding.

H. Insurance Expense

1. Introduction

During the test year, the Company booked $5,909,663 in insurance premium expense (Exh. NG-RRP-2, at 17 (Rev. 3)). The Company has proposed to reduce its test year cost of service by $1,033,234 based on the most recently received insurance premium billings and their respective allocations to MECo and Nantucket Electric (Exhs. NG-RRP-1, at 33: NG-RRP-2, at 17 (Rev. 3)). Of the 14 types of insurance coverage represented by the proposed adjustment, four policies (i.e., Public (Excess) Liability, Business Interruption, Property, and Property

Terrorism insurance) are provided to the Company by National Grid Insurance USA LLC ("NGI USA"), a wholly owned subsidiary of National Grid USA (Exh. NG-RRP-2, at 17 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues the Company's premium payments to NGI USA should not be included in insurance expense because (1) the Company has not demonstrated that it took reasonable measures to control costs associated with its NGI USA policies; (2) the Company has not complied with the Department's regulations on affiliate transactions; and (3) the NGI USA business interruption policy allows for double recovery (Attorney General Brief at 50-55). The Attorney General asserts that removing payments to NGI USA will result in a $2,414,233 reduction to the Company's insurance expense (Attorney General Brief at 50, citing Exh. NG-RRP-2, at 17 (Rev. 3)).

First, regarding cost containment, the Attorney General argues that the Department includes the most current cost of liability and property insurance as a reasonable cost of service. (Attorney General Brief at 50, citing Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55, at 276 (2010)). However, to be included in the cost of service, the Attorney General contends that the Company must provide evidence that it undertook reasonable measures to control property and liability insurance expense (Attorney General Brief at 50, citing D.P.U. 10-55, at 275-276; New England Gas Company, D.P.U. 08-35, at 119-120 (2009); D.T.E. 05-27, at 133-134; Boston Gas Company, D.T.E. 03-40, at 184-185 (2003)). Further, the Attorney General claims that the Company's evidence of cost containment should be provided as a narrative in its initial filing (Attorney General Brief at 51, citing D.P.U. 10-55, at 276).

The Attorney General argues that despite these requirements, the Company's prefiled testimony is limited to representations that its proposed insurance expense is known and measurable on the basis of recent insurance bills received, and there is no demonstration that the Company undertook reasonable measures to controls such expenses (Attorney General Brief at 51, citing Exh. RRP-1, at 33). Further, the Attorney General contends that during the proceedings, the Company was unable to explain: (1) the measures it took to control costs related to NGI USA; (2) the basis for selecting NGI USA as the Company's carrier for public excess liability insurance, business interruption insurance, property insurance, and property terrorism insurance; and (3) the basis for any premium charged under any insurance policy (Attorney General Brief at 51-52, citing Exh. AG-1-63; Tr. 6, at 862, 864). Based on these considerations, the Attorney General asserts that there is no evidence in the record that would support how the premiums are determined and whether or not they were reasonable or prudent (Attorney General Brief at 52, citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001), citing Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967); Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963)).

Next, the Attorney General argues that even if the Department finds that the Company provided sufficient explanation of cost containment measures, the Company's premium payments to NGI USA should not be allowed as part of its cost of service because the payments violate the Department's affiliate transaction regulations (Attorney General Brief at 52).

According to the Attorney General, NGI USA is an affiliate of the Company, as defined by G.L. c. 164, § 85 ("§ 85") (Attorney General Brief at 53).[158]

In particular, the Attorney General contends that NGI USA was established to provide insurance coverage to National Grid's operating companies, thus being created to serve and benefit the Company (Attorney General Brief at 53, citing RR-AG-33). Further, the Attorney General claims that the Company discusses its "insurance captives" and "insurance subsidiary undertakings" in its annual reports to shareholders (Attorney General Brief at 53, citing Exh. AG-1-2-3(1g), Att., at 119, line 2-3, 133, 190).

The Attorney General asserts that Department regulation[159] and good utility practice require evidence that any affiliate services are priced at no more than market value. According

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158 G.L. c. 164, § 85, provides, in pertinent part:

> . . . "affiliated company" shall mean any corporation, society, trust, association, partnership or individual (a) controlling a company subject to this chapter, either directly, by ownership of a majority of its voting stock or of such minority thereof as to give it substantial control of such company, or indirectly, by ownership of such a majority or minority of the voting stock of another corporation or association so controlling such company; or (b) so controlled by a corporation, society, trust, association, partnership or individual controlling as aforesaid, directly or indirectly, a company subject to this chapter; or (c) standing in such a relation to a company subject to this chapter that there is an absence of equal bargaining power between the corporation, society, trust, association, partnership or individual and the company so subject, in respect to their dealings and transactions.

159 220 C.M.R. § 12.04(3) provides:

> An Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided.

to the Attorney General, the Department is required to carefully scrutinize affiliate transactions because "the exercise of control and the absence of an arm's length bargaining" may lead to "'excessive charges for services . . . .'" (Attorney General Brief at 53, citing D.P.U. 12-86, at 11; Public Utility Holding Co. Act of 1935, P.L. No. 333 (1935), 49 Stat. 803, § 1 (1935); Report of the Special Committee on Control and Conduct of Public Utilities, (1930 H. 1200, § 31)). Consequently, the Attorney General argues that if affiliate costs are excessive, they should be excluded from the revenue requirement (Attorney General Brief at 53-54, citing G.L. c. 164, § 94B)). In this regard, the Attorney General contends that National Grid failed to offer any evidence to demonstrate that the amount of premiums charged to the Company by NGI USA are at or below the market price (Attorney General Brief at 54, citing Exh. NG-RRP-2, at 17 (Rev. 3)). Thus, the Attorney General asserts that the Department should disallow these payments to be included in rates and the cost of service should be reduced by $2,414,233 (Attorney General Brief at 54).[160]

Finally, the Attorney General argues that the Company's cost for its business interruption insurance should be disallowed because a claim for loss of income under the policy would amount to double recovery (Attorney General Brief at 54). According to the Attorney General, the Company already is made whole for reductions to income through its RDM (Attorney General Brief at 54). Specifically, the Attorney General contends that National Grid pays annual premiums of $103,968 for a business interruption policy that indemnifies the Company for

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[160] The Attorney General provides a breakdown of the premiums as follows: (1) $965,005 in Public (Excess) Liability Insurance premiums; (2) $103,968 in Business Interruption Premiums; (3) $1,296,816 in Property Insurance premiums; and (4) $48,444 in Property Terrorism Insurance premiums (Attorney General Brief at 54, citing Exh. NG-RRP-2, at 17 (Rev. 3)).

reductions to income as a result of the interruption or interference with the business (Attorney General Brief at 55, citing Exh. NG-RRP-2, at 17 (Rev. 3); RR-AG-30, Att. at 49). The Attorney General notes that "income" is defined in the policy as "the sum of gross earnings and/or sales and/or income and/or revenue derived from the [b]usiness." (Attorney General Brief at 53, citing RR-AG-30, Att. at 50). The Attorney General reasons that because National Grid's RDM makes the Company whole for reductions in revenues, the Company receives the same amount of revenue for its distribution services regardless of whether there is an interruption to the Company's operations (Attorney General Brief at 55, citing Exhs. NG-MLR-1; NG-RRP-1). Consequently, the Attorney General argues that a claim under the business interruption policy for reduced income would amount to a double recovery from customers (Attorney General Brief at 55). Therefore, the Attorney General asserts that costs for the Company's business interruption policy should be excluded from insurance expense and the Company's proposed cost of service should be reduced by $103,968 (Attorney General Brief at 55).

b. Company

First, regarding cost containment, National Grid disputes the Attorney General's claim that the Company has not demonstrated that it undertook reasonable measures to control costs associated with NGI USA, and challenges the Attorney General's position that such a demonstration is required a part of the initial filing (Company Brief at 61). The Company contends that in each of the cases relied on by the Attorney General, the petitioner sought an increase to test year insurance expense, and that the Department's reference to "reasonable efforts to control costs" pertained to the requested increase in expense (Company Brief at 61, citing D.P.U. 10-55, at 274-276 (requesting a post-test year increase of $376,488); D.P.U. 08-35,

at 119-120 (requesting a post-test year increase $225,993); D.T.E. 05-27, at 132 (requesting a post-test year increase of $94,997, subsequently adjusted); D.T.E. 03-40, at 184-185 (requesting a post-test year increase of $607,287)). National Grid notes that, in this case, the Company is seeking to decrease its test year expense, which, in itself, demonstrates that the Company has controlled costs so that the rate-year expense is less than the test year expense (Company Brief at 61). According to National Grid, there is no basis for disallowance of a significant amount of expense on the basis that the Company had an affirmative obligation to demonstrate cost control in the prefiled testimony where there is no increased cost requiring such demonstration (Company Brief at 63).

National Grid also challenges the Attorney General's claim that during the proceedings the Company was unable or failed to adequately respond to inquiries regarding the selection of NGI USA or the basis for recovery of insurance expense (Company Brief at 62-63, citing Exh. AG-1-63; Tr. 6, at 862-865; RR-AG-33). In this regard, National Grid notes that the Attorney General made no attempt to examine the reasons that insurance expense is decreasing (Company Brief at 63-64). The Company asserts that there is no basis for disallowance of insurance expense where there is no reasonable inquiry made into the proposed adjustment (Company Brief at 63).

Turning to its use of NGI USA, National Grid argues that the Department has previously found that the procurement of insurance coverage through "captive" or affiliated insurance companies can be effective to reduce costs to customers (Company Brief at 64). According to the Company, captive insurance companies are known to be a cost-efficient alternative to risk transfer because the arrangement leverages the use of reinsurance markets and puts the captive

insurance carriers in competition against markets that underwrite in the conventional direct insurance marketplace, thereby driving down the cost below what would be available solely by using conventional direct writing insurers (Company Brief at 64, citing Bay State Gas Company, D.P.U. 13-75, at 181, 193-194 (2013)).

Second, the Company argues that there is no evidence that the premium cost charges by NGI USA are "excessive" or above market (Company Brief at 64). According to the Company, mandates of NGI USA include providing insurance coverage to National Grid USA's operating companies at rates that are at or below those that can be achieved in the commercial insurance markets, as well as enhanced policy coverage beyond what is available in those markets (Company Brief at 64-65, citing RR-AG-33).

Moreover, the Company contends the Department does not routinely review or render determinations on whether insurance premiums charged by affiliates are at or below the market price where the petitioning utility is not asking for any increase in the test year amount (Company Brief at 65). The Company claims that a petitioning company cannot foresee every specific area of inquiry of interest to the other parties, and that the law places some obligation on other parties to raise issues during the preceding so that there is an opportunity for rebuttal (Company Brief at 65, citing Fitchburg Gas & Electric Light Co. v. Department of Public Utilities, 375 Mass. 571, 578 (1978); NYNEX, D.P.U. 86-33-G at 74 (1989); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 33 (1983)). Therefore, the Company asserts that its arrangement with NGI USA does not result in a violation of the Department's affiliate regulations (Company Brief at 65).

Finally, the Company disputes the Attorney General's claim that the business interruption policy constitutes "double recovery" of expenses (Company Brief at 66). In this regard, the Company argues that it would never make an insurance claim, nor would it be lawfully eligible for a claim of lost revenues, where the revenues were recovered through the revenue-decoupling mechanism (Company Brief at 66). Further, the Company contends that the Attorney General ignores the other coverage protections that are not driven by reductions in consumption and would not be recovered through the ratemaking process, primarily relating to continuing operations, contractual agreements and other items (Company Brief at 66, citing RR-AG-30, Att.). National Grid claims that it would be unreasonable and imprudent for the Company to forego business interruption coverage and that the ultimate cost of not carrying such insurance would fall on the customers (Company Brief at 66-67). For these reasons, the Company concludes there is no unwarranted cost or "double recovery" of revenue loss that occurs due to the availability of this policy (Company Brief at 67).

3. Analysis and Findings

a. Introduction

Under current ratemaking practice, the Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; North Attleboro Gas Company, D.P.U. 86-86, at 8-10 (1986); D.P.U. 84-94, at 44. The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185.

b. Cost Containment

Concerning National Grid's efforts to control costs associated with its NGI USA policies, the cases relied on by the Attorney General each involve proposed increases to test year insurance expense. D.P.U. 10-55, at 274-276 (requesting a post-test year increase of $376,488); D.P.U. 08-35, at 119-120 (requesting a post-test year increase $225,993); D.T.E. 05-27, at 132 (requesting a post-test year increase of $94,997, subsequently adjusted); D.T.E. 03-40, at 184-185 (requesting a post-test year increase of $607,287). In this case, the Company is seeking to decrease test year insurance expense by $1,033,234 (Exhs. NG-RRP-1, at 33; NG-RRP-2, at 17 (Rev. 3)). In this instance, the Department finds that the reduced premium billings from NGI USA and the Company's proposed reduction in the cost of service constitute sufficient evidence that the Company has controlled its insurance costs.[161]

As stated above, the Department considers measures by utilities to control property and liability insurance expense to be important in reviewing a company's cost of service. The Department's review of these cost control measures typically focused on instances of increased costs. Efforts by utilities to manage their insurance coverage with a consideration of costs also are important where premium costs are decreased. Thus, the Department requires companies in their base rate cases to identify reasonable measures to control property and liability insurance expenses, whether the insurance costs are increasing or decreasing.

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161 While the Company's insurance expense has increased since the 2008 test year used in its previous rate case, we are unable to conclude that an increase in costs over an eight-year period is in itself evidence of a failure in cost-containment efforts.

c. Affiliate Transactions

The Attorney General argues that, even if the Department finds that the Company demonstrates cost-control measures associated with its NGI USA insurance policies, the Company's premium payments to NGI USA should not be allowed as part of its cost of service because they violate the Department's affiliate transaction regulations (Attorney General Brief at 31). Specifically, the Attorney General claims that the Company has not demonstrated that its payments to NGI USA are not excessive, and that there is no evidence that the amount NGI USA charges the Company for premiums are at or below market price (Attorney General Brief at 31).

NGI USA provides insurance coverage to National Grid as a "captive" or affiliate insurance company. The Department previously has found that procurement of insurance coverage through "captive" or affiliated insurance companies can be effective to reduce costs to customers. Captive insurance companies are known to be a cost-efficient alternative to risk transfer because the arrangement leverages the use of reinsurance markets and puts the "captive" insurance carriers in competition against markets that underwrite in the conventional direct insurance marketplace, thereby driving down the cost below which would be available by solely using conventional direct writing insurers. Bay State Gas Company, D.P.U. 13-75, at 181, 193, 194; see also Boston Edison Company, D.P.U. 376, at 13-14 (1981).

We affirm our findings regarding the benefits of the procurement of insurance coverage through "captive" or affiliate insurance companies. Given this precedent and the absence of evidence in this case of excessive or above-market premiums paid by the Company to NGI USA, the Department allows these costs and finds no grounds to assert a violation of the Department's affiliate transaction rules. Further, within a substantial range, business decisions are matters for

a company's determination. Fitchburg Gas and Electric Light Company, 375 Mass. 571, 578 (1978). However, when a company's determination is challenged, it must come forward with evidence to support its decisions and show that they are not inconsistent with valid policies of the Department. 375 Mass. at 578-579. Regarding the use of affiliate insurance companies, the Department has not established any specific filing requirements or analysis for companies to support the associated insurance expenses. Also, the Attorney General's challenge was on brief, eliminating the opportunity for the Company to present evidence in support of its procurement of insurance coverage from NGI USA. See D.P.U. 95-118, at 143; The Berkshire Gas Company, D.P.U. 92-210, at 102 (1993); Commonwealth Gas Company, D.P.U. 87-122-B at 54 (1989). Based on the circumstances of this case, we rely on the business judgment of National Grid in procuring insurance coverage from NGI USA, and we do not reduce the Company's cost of service based on the challenge of the Attorney General.

Although the Department continues to recognize the benefits of jurisdictional companies' procuring insurance through affiliate insurance companies, we find that our review of this type of arrangement would be served by a company's production of specific information. Accordingly, where a company procures insurance coverage from an affiliate insurance company, the jurisdictional company shall in its base rate case provide the following information: (1) whether comparative studies are performed to identify the relationship between affiliate premiums and premiums available in commercial markets; (2) whether such a comparative analysis was performed during the test year; (3) whether there is documentation that the affiliate insurance company's premiums are lower than premiums to the company for comparable coverage in the

commercial insurance markets; and (4) whether affiliate insurance providers are able to provide broader coverage to the company than what is commercially available in the marketplace.

d. Business Interruption Policy

Finally, the Attorney General challenges the need for the Company's business interruption policy, because of the potential for "double recovery" through costs both recovered under the policy and recovered through the RDM (Attorney General Brief at 54). On a basic level, business interruption insurance covers the loss of income that a business suffers after a disaster. Under the coverage provided by NGI USA, National Grid is indemnified for "actual loss sustained" resulting directly from interruption of or interference with National Grid's operations, activities, or services due to an "occurrence"[162] affecting National Grid's property (RR-AG-30, Att. at 9, 27, 49). Actual loss sustained includes reduction in income, continuing obligations payable following the interruption or interference, the amount of a loss under a contractual agreement payable as a result of the interruption or interference, and extra expense incurred to continue usual operations, which are over and above normal costs to conduct operations (RR-AG-30, Att. at 49-51).

Based on our review of the record, we find that the Company's business interruption insurance coverage would not lead to double recovery. As National Grid represented, the Company could not make a claim for lost under its business interruption policy where the

[162] An occurrence includes such events as windstorm, tornadoes, hail, rainstorm, electrical storm, cyclones, hurricanes, similar storms and systems of winds of a violent and destructive nature, earthquake shock, volcanic eruption, tsunami, seaquake, tidal wave, sub-sea mud slide (RR-AG-30, Att. at 10).

revenues were recovered through its RDM.[163] In addition, the Company's policy covers more than a reduction in income, such as obligations payable following the interruption or interference, losses under contractual agreements that are payable as a result of the interruption or interference, and expenses incurred over and above the usual costs of operations (RR-AG-30, Att. at 49-51). These losses are not associated with customers' usage or distribution revenues.

Also, as stated above regarding National Grid's procurement of insurance coverage from NGI USA, with the absence of evidence in this case of double recovery or unreasonable insurance costs, the Department relies on the business judgment of National Grid in procuring business interruption insurance. Therefore, the Department does not reduce the Company's cost of service for its costs for business interruption insurance.

e. Conclusion

Based on the foregoing, the Department finds that the Company's insurance expense premiums are based on actual policy rates, and are thus known and measurable. Therefore, the Department approves the Company's proposed adjustments. Accordingly, the Department accepts the Company's proposal to reduce its test year insurance expense by $1,033,234.

I. Rate Case Expense

1. Introduction

Initially, the Company estimated it would incur $1,512,785 in rate case expense (Exhs. NG-RPP-1, at 35; NG-RRP-2, at 22). Based on its final invoices and projected costs to

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163 Under the Company's RDM, the Department establishes the Company's target annual distribution revenues in base rate case. On an annual basis, the Company reconciles its actual distribution revenues to the target revenues, and collects from customers an amount less that its target revenues (or returns to customers an amount greater that its target revenues) (Revenue Decoupling Mechanism Provision, M.D.P.U. No. 1289).

complete the compliance filing, the Company proposes a final rate case expense of $1,245,607 (Exh. NG-RRP-2, at 22 (Rev. 3)). National Grid's proposed rate case expenses include costs related to legal support services, miscellaneous expenses associated with preparing the rate case (e.g. compact disc and flash drive preparation, bound copies of filings, tabs, couriers, etc.), and expert services related to the following: (1) marginal distribution cost study; (2) depreciation study; and (3) cost of capital/ROE (Exhs. NG-RRP-2, at 22 (Rev. 3); DPU-7-1; DPU-7-14 (Supp. 2); RR-AG-32, Atts.).

National Grid proposes to normalize its rate case expense over a period of five years (Exhs. NG-RRP-1 at 35; DPU-7-20). The Company argues that this normalization period is consistent with the provisions of § 94, which requires electric companies to file general rate cases no less frequently than at five-year intervals (Exhs. NG-RRP-1, at 35; DPU-7-20). Normalizing the Company's proposed rate case expense of $1,245,607 over five years produces an annual expense of $249,121 (Exh. NG-RRP-2, at 26 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has not met its burden to justify full recovery of rate case expense in this proceeding (Attorney General Brief at 60). Specifically, the Attorney General contends that the Company failed to limit the costs associated with outside witnesses, particularly in the areas of cost of capital/ROE and legal services, and failed to offer a proposal for shareholders to bear a portion of rate case expenses (Attorney General Brief at 61). According to the Attorney General, a request for proposals ("RFP") process is insufficient to adequately control rate case expense (Attorney General Brief at 61).

With respect to the retention of outside witnesses, the Attorney General argues that because National Grid is a large company, it should have assigned more internal company employees to sponsor testimony and more internal counsel to perform legal work on the rate case (Attorney General Brief at 61). Thus, the Attorney General asserts that the Department should exercise its discretion and reduce recovery of expenses associated with the Company's cost of capital witness and outside legal services by 50 percent (Attorney General Brief at 61).

Alternatively, the Attorney General recommends that shareholders should be assigned at least 30 percent of the cost of outside legal services (Attorney General Brief at 62; Attorney General Reply Brief at 34). In this regard, the Attorney General notes that the Company, after an RFP process, retained a legal service provider whose proposal was 30 percent higher than the next lowest bidder (Attorney General Brief at 62-63; Attorney General Reply Brief at 34). Further, she contends that the next highest bidder had substantial utility experience and prior experience practicing before the Department (Attorney General Brief at 62; Attorney General Reply Brief at 34). The Attorney General asserts that because the Company failed to show that the next highest bidder could not perform the work necessary to litigate this rate case shareholders should be responsible for 30 percent of the costs associated with the retained legal service provider (Attorney General Brief at 62-63; Attorney General Reply Brief at 34).

Finally, the Attorney General rejects any notion that predicting actual costs is difficult or that the bids provided by the selected legal service provider and the next highest bidder were difficult to compare because the providers used different "inputs and assumptions" in developing their respective bids (Attorney General Reply Brief at 34-35). According to the Attorney General, National Grid should have provided adequate inputs and assumptions for the bidding

firms to use in their estimates so that the Company could have an objective benchmark of comparison (Attorney General Reply Brief at 35). Further, she asserts that if the price structures and fees of these bids are truly incomparable because of widely different inputs and assumptions, then the Company did not conduct a "fair, open, and transparent" competitive bidding process (Attorney General Reply Brief at 35).

b. Company

The Company argues that it contained rate case expenses in several ways. First, the Company contends that it used internal personnel and resources whenever practicable given internal expertise and existing workload requirements (Company Brief at 80, 82). Second, National Grid claims that for certain non-routine work that required the use of outside consultants with specialized expertise or experience, the Company engaged in an RFP process to select the most qualified and cost-effective service provider (Company Brief at 80, 84-89).

With respect to the RFP process, the Company argues that it used an internal review committee to evaluate bids based on price and non-price factors, including vendor qualifications; relevant experience; capabilities and personnel to support the rate petition; proposed fee structure; and other factors (Company Brief at 79, citing Exh. DPU-7-2).[164] The Company concedes that it did not select the lower cost bidder for its depreciation analysis, cost of capital/ROE analysis, and legal services provider (Company Brief at 80, citing Exh. DPU-7-3).

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164 In particular, the Company notes that each outside service provider executed a Project Statement, which contained a detailed scope of work with a "not-to-exceed" cost amount (Company Brief at 82, citing Exhs. DPU-7-15; DPU-7-16). According to the Company, any potential increase in costs would be reviewed, subject to negotiation and documented through a project change request (Company Brief at 82). Further, the Company notes that its engagement with outside service providers included written policies designed to control travel, lodging, meals and other similar expenses, and prohibited markups on expenses or direct costs (Company Brief at 82).

However, the Company argues that it gave proper consideration to price and non-price factors in selecting reasonably priced service providers who possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks to be performed (Company Brief at 88, citing D.P.U. 13-75, at 241).

More specifically, National Grid justifies its retention of its depreciation-related service provider based on efficiencies gained through a past relationship and the provider's knowledge of the Company's operations (Company Brief at 80, citing Exh. DPU-7-3). With respect to its cost of capital/ROE service provider, the Company contends that a strict cost comparison among bids would inappropriately favor a bidder who underestimated the level of time and effort for litigation in this case (Company Brief at 80, citing Exh. DPU-7-3). Thus, the Company claims that it reviewed average hourly labor rates for different bidders and compared them on a normalized level of time, which resulted in the selected service provider having the lowest effective bid (Company Brief at 80, citing Exh. DPU-7-3).

Regarding legal counsel, the Company argues that it selected a legal services provider that has extensive rate case experience in Massachusetts, is thoroughly familiar with the Department's practices for rate case management, and offered a fee structure that was competitive with other RFP respondents (Company Brief at 80-81, citing Exh. DPU-7-3). On this last point, National Grid argues that when analyzed on a standard hourly fee basis, the selected service provider offered hourly rates that were significantly lower than other bidders, and its estimate of labor hours was more consistent with the actual number of hours needed to fully support the rate case (Company Brief at 85, citing Exh. DPU-7-3, Att.). National Grid

rejects the notion that choosing a legal service provider based solely on estimated costs is appropriate because each bidder uses its own inputs and calculus in developing bids, and total number of hours actually required to litigate the case is largely a function of the number of discovery requests received and the number and nature of the issues raised by intervenors, factors over which the Company has no control (Company Brief at 86). Thus, the Company asserts that a "hard cap" for recovery of rate case expense based on cost estimates is punitive (Company Brief at 86). Further, National Grid contends that there is no evidence to suggest that selecting a different legal service provider would have resulted in a lower actual costs, particularly since the actual hours that ultimately are spent litigating the case are unknown at the time that the RFP responses are submitted (Company Brief at 87).

Finally, National Grid argues that it properly considered shareholder responsibility for a portion of rate case expense (Company Brief at 82-83, citing Exh. DPU-7-20). In this regard, the Company contends that shareholders already bear a portion of rate case expense because: (1) the Department's ratemaking treatment of rate case expense does not guarantee dollar-for-dollar recovery; (2) if the Company files another base rate case before the expiration of the normalization period attributable to the rate case expense in this proceeding, the Company will not fully recover all of such rate expense; (3) to the extent rate case expense is not fully recovered, the Company's earned rate of return will be negatively impacted, which has a direct impact on shareholders; and (4) even if the normalization period matches the period between rate

cases exactly, the Company and its shareholders are not reimbursed for actual carrying costs (Company Brief at 83, citing Exhs. DPU-7-20; AG-8-19).[165]

Based on these considerations, the Company asserts that there is no basis for the Department to reduce the Company's rate case expense as recommended by the Attorney General (Company Brief at 85, 89).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has been actually incurred, and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 227.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 241-242; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192. All companies are on notice that the risk of non-recovery of rate case expense looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40,

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165 The Company also argues that, in this particular case, shareholders are bearing the costs related to the PwC Report, which was discussed above in Section III (Company Brief at 83).

at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also D.P.U. 93-223-B at 16-17.

b. Competitive Bidding

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114 at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with the competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101;

D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective, and based on an RFP process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential service providers to provide complete bids, and provide the company with sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which service provider may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for rate case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expenses, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

ii. National Grid's Request for Proposal Process

The Company conducted a competitive bidding process to retain outside consultants associated with its: (1) marginal distribution cost study; (2) depreciation analysis; (3) cost of

capital/ROE analysis; and (4) legal services (Exhs. DPU-7-1; DPU-7-6; AG-8-14). The Company bears the burden to demonstrate that its choices of outside consultants and legal service provider are reasonable and cost effective. D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153.

As an initial matter, we note that the Company evaluated the capabilities of its internal staff, including access to data, expertise, and experience, in determining whether to retain the selected outside service providers (Exh. DPU-7-5). We find that the Company's decision to retain outside consultants, rather than using internal personnel, to perform these tasks is reasonable given the complexity of the issues and the overall scope of this rate case.

The Company received at least three bids in each of the four categories for which it sought outside consultant services (Exhs. DPU-7-1, at 2; DPU-7-2). The record demonstrates that bids were internally reviewed through an analysis of a number of factors including strength of proposals, familiarity with the Company's operations, industry experience, cost, approach, and project management (Exh. DPU-7-2 & Atts.).

The Department has reviewed the bids associated with the four categories of rate case expense for which the Company conducted a competitive solicitation, as well as the scoring and evaluation material submitted by the Company and other evidence regarding the selection process, and we have considered the related arguments of the parties (Exhs. DPU-7-1 & Atts.; DPU-7-2 & Atts.; DPU-7-3; DPU-7-5). We are satisfied that the selection process was appropriate and that the bidders were scored and evaluated in a reasonable and equitable manner. We decline to substitute our judgment for that of the Company in evaluating each bidder against each criterion. Further, we find that National Grid gave appropriate weight to the billing

structures of the various bidders and any differences among them, and considered other important price factors, such as price caps and other cost-containment features, and important non-price factors as well, such as familiarity with Department precedent and the Company's operations (Exhs. DPU-7-1, Atts.; DPU-7-2) & Atts.; DPU-7-3; DPU-7-5; DPU-7-15; DPU-7-16; DPU-7-17).

The Company concedes that it did not select the lowest cost bidder for its depreciation consultant, cost of capital/ROE witness, or legal services provider (Company Brief at 80, citing Exh. DPU-7-3). The Attorney General challenges the retention of National Grid's cost of capital/ROE consultant and legal services provider because of this purported deficiency (Attorney General Brief at 61-62; Attorney General Reply Brief at 34).

The Department does not require a company to choose the lowest bidder, provided that the company adequately justifies its decision to do so. See D.P.U. 10-70 at 153; D.T.E. 03-40 at 153. As an initial matter, we note that although all three selected providers were not the lowest bidders, we conclude that the amount of the respective bids was not unreasonable or disproportionate to the overall scope of work provided by these providers (see Exhs. DPU-7-1, Atts. 2(c); 3(e), 4(b); DPU-7-14, Atts. 2, 3 (Supp. 2)).

With respect to the depreciation analysis, the record shows that the selected provider had performed similar work for the Company in the past and compiled historical asset data necessary to perform services in this case (Exhs. DPU-7-3, at 1; DPU-7-5, at 1-2). As such, it is reasonable to expect that the foundational process required for a new provider would be time consuming and require costs that the selected service provider did not incur (Exh. DPU-7-3, at 1). Based on these considerations, we conclude that it is unlikely that an alternative service provider could

duplicate these specialized services for a lower cost. Therefore, we find that the Company's selection of its depreciation-related consultant was reasonable, prudent and appropriate.

With respect to the cost of capital/ROE consultant, the record shows that the bids detailed different estimates of anticipated effort for the adjudicatory phase of the proceeding with no caps on cost (Exhs. DPU-7-1, Atts. 3(a) through (e); DPU-7-2, Att. 3; DPU-7-3, at 1). As a result, the Company performed a more detailed analysis of the bids and cost comparison (Exhs. DPU-7-2, Att. 3; DPU-7-3, at 2). The result of this analysis shows that the selected bidder compares favorably with the remaining bidders in terms of cost (Exh. DPU-7-2, Att. 3; DPU-7-3, at 2). In addition, the Company considered level of expertise, experience and litigation support that the selected provider would contribute to the proceeding, as well as the prior relationship and familiarity with the Company's operations (Exhs. DPU-7-2, Att. 3; DPU-7-3, at 2). In light of these factors, we find that the Company's selection of its cost of capital/ROE consultant was reasonable, prudent and appropriate.

Finally, with respect to the legal services provider, we find that National Grid gave appropriate weight to the billing structures of the various bidders and any differences among them, and considered other price factors, such as price caps, estimated hours of labor, and cost-containment features (Exhs. DPU-7-2 & Att. 4; DPU-7-3, at 2 & Att.). We are not persuaded by the Attorney General's suggestion that a comparison of cost estimates should have been the driving factor in the Company's decision. Rather, we conclude that National Grid appropriately considered other important factors in selecting its legal service provider, including the selected provider's rate case experience, knowledge of the electric industry and Department precedent, previous close working relationship with the Company, and familiarity with Company

operations (Exhs. DPU-7-2 & Att. 4; DPU-7-3, at 2 & Att.). Further, as noted above, the cost estimate provided was not unreasonable or disproportionate to the overall scope of work provided by this provider, particularly in light of the complexity of the case and the number of issues presented (see Exhs. DPU-7-1, Att. 4(b); DPU-7-14, Atts. 2, 3 (Supp. 2)). Based on these considerations, we find that the Company's selection of its legal service provider was reasonable, prudent and appropriate.

For all of the foregoing reasons, we conclude that the Company conducted a fair, open and transparent RFP process in selecting all of its outside consultants and legal services provider. Further, we find that the Company provided a sufficient justification for not selecting the lowest bidder for its depreciation analysis, cost of capital/ROE consultant, and legal services provider. Accordingly, we decline to adopt the Attorney General's recommendations to disallow a portion of rate case expense recovery on the basis that the Company failed to control costs by not selecting the lowest bidder.

c. Various Rate Case Expenses

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by the Company and finds that such invoices are properly itemized (Exh. DPU-7-14, Att. 1 (Supp. 2)). Further, we find that the total costs associated with each service provider were reasonable, appropriate, proportionate to the overall scope of work provided, and prudently incurred (Exh. DPU-7-14, Att. 1 (Supp. 2)).

In addition, the Company seeks to include proposed miscellaneous costs of $133,603.64 (Exh. DPU-7-14, Att. 3 (Supp. 2)). These miscellaneous costs include costs related to case production expenses (Exh. DPU-7-14, Att. 3 (Supp. 2)). Neither the Attorney General nor any other party challenges the inclusion of these costs in rates. Nevertheless, the Company bears the burden of demonstrating that these costs are reasonable and appropriate and were prudently incurred. D.P.U. 10-114, at 220, 224-225; D.P.U. 95-118, at 115-119.

The Department has reviewed the invoices provided by the Company for these miscellaneous costs and finds that such invoices are properly itemized (Exh. DPU-7-14, Att. 1 (Supp. 2)). Further, given the nature and scope of this complex proceeding, the Department finds that these miscellaneous costs are reasonable and appropriate and were prudently incurred (Exh. DPU-7-14, Att. 1 (Supp. 2)).

d. Fees for Rate Case Completion

The Company has included $30,000 in its proposed rate case expense as a compliance phase flat fee for legal services (Exhs. DPU-7-14, Att. 2 (Supp. 2)). This amount is included in the proposed final rate case expense amount of $1,245,607 (Exhs. DPU-7-14, Att. 2 (Supp. 2); DPU-7-14, Att. 3, at 1 (Supp. 2)).

The Department's long-standing precedent allows only known and measurable changes to test year expenses to be included as adjustments to cost of service. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161; D.T.E. 02-24/25 at 195; D.T.E. 98-51 at 61-62. Proposed adjustments based on projects or estimates are not known and measurable, and recovery of those expenses is not allowed. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not preclude recovery of fixed fees for completion of

compliance filing work in a rate case but the reasonableness of the fixed fees must be supported by sufficient evidence. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts for services to complete a case after the record closes and briefs are filed, a company may qualify to recover such expenses. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Documented and itemized proof is a prerequisite for recovery. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to a compliance filing. D.P.U. 10-114, at 237; D.P.U. 10-55, at 338.

The Department has reviewed the Company's basis for its proposed fixed fee and has determined that this fixed fee is reasonable and supported by sufficient evidence (Exh. DPU-7-1, Att. 4(b)). Accordingly, we allow the Company to recover these costs as part of its rate case expenses.

e. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the experience of an appropriate period, and then compare it to the test year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163;

D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77; D.P.U. 1490, at 33. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include in the cost of service a representative annual level of rate case expense. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

Typically, the Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four rate cases, including the present case, rounded to the nearest whole number. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n. 77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

The Company calculates a normalization period of six years, and states that its calculation is consistent with Department precedent (Exh. AG-8-20, Att.). However, the Company proposes a rate case expense normalization period of five years based on the directives set forth in § 94 that electric companies shall file general rate cases no less frequently than at five-year intervals (Exh. DPU-7-20). Neither the Attorney General nor any other party challenges the Company's proposal to normalize rate case expense over the five year period.

As an initial matter, we note that, under Department precedent, the Company incorrectly calculated its normalization period of six years (see Exh. AG-8-20, Att.). The correct application

of Department precedent would result in a normalization period of eight years.[166] However, we find that the § 94 requirement for electric companies to file rate cases every five years effectively caps the normalization period at five years. Therefore, in instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, such as in the instant case, we will instead impose a five-year normalization period.[167] Accordingly, the Department approves the Company's normalization period of five years.

f. Requirement to Control Rate Case Expense

The Attorney General argues that the Department should reduce a portion of National Grid's recovery of rate case expense because the Company failed to adequately control costs (Attorney General Brief at 62; Attorney General Reply Brief at 34). Based on our findings above, we decline to adopt the Attorney General's recommendations on this basis. Further, the Company has shown that it considered the issue of cost-sharing rate case expense between ratepayers and shareholders, and we find that the Company has provided sufficient justification for not proposing that shareholders bear a portion of the rate case expense incurred in this proceeding (Exhs. DPU-7-20; AG-8-19).

Since the establishment of the requirement for companies to propose a rate case expense cost-sharing arrangement, the Department has had an opportunity to evaluate companies'

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166 Based on the Company's filing dates for the last four rate cases, between D.P.U. 15-155 and D.P.U. 09-39, the interval is 5.5 years; between D.P.U. 09-39 and D.P.U. 95-40, the interval is 14.16 years; and between D.P.U. 95-40 and D.P.U. 92-78, the interval is 3 years. The sum of these intervals, divided by three and rounded to the nearest whole number results in a normalization period of eight years: 22.66 years/3 = 7.55 (rounded to eight).

167 Where a normalization period calculated pursuant to Department precedent is less than five years, this lesser period shall apply.

responses. See, e.g., D.P.U. 14-150, at 224-227; D.P.U. 13-90, at 177-181; D.P.U. 13-75, at 245-246; D.P.U. 12-25, at 204-207. In each instance, we have accepted a company's decision not to propose a specific cost-sharing arrangement. As noted, we accept National Grid's explanation in this case as well.

We recognize that the Department's ability to disallow a company's recovery of rate case expense for failure to adhere to our strict requirements concerning competitive bidding, or for failure to pursue other reasonable cost-containment measures, or for failure to properly itemize rate case expense invoices, provides a sufficient incentive for companies to control rate case expense. Further, we recognize that the nature of normalized rate case expense recovery (i.e., not dollar-for-dollar recovery) is such that shareholders already absorb a portion of rate case expense, even in light of the § 94 requirement for electric companies to file rate cases every five years (see Exh. DPU-7-20).

Based on these considerations, we no longer will require companies to file a specific proposal for shareholders to bear a portion of rate case expense. However, we cannot overemphasize that this decision in no way minimizes our focus on the importance of cost containment. We will continue to closely scrutinize the RFP process to ensure that it is rigorous and demonstrates that outside service providers chosen are reasonable and cost effective. See D.P.U. 14-150, at 226-227; D.P.U. 13-90, at 177-178. In addition to a thorough RFP process, the Department expects cost containment provisions to be included in rate case expense and companies to be aggressive in their cost control measures. D.P.U. 14-150, at 226-227; D.P.U. 13-90, at 177-178. The Department will continue to exercise its discretion to disallow recovery of rate case expense where a company fails to adhere to these requirements, as well as

in instances where the amount of overall rate case expense appears to be excessive or disproportionate to the work performed.

4. Conclusion

The Company originally proposed an annual rate case expense of $302,557 based on an estimated total rate case expense of $1,512,785 (Exhs. NG-RPP-1, at 35; NG-RRP-2, at 22). The Company subsequently proposed to reduce the annual level of recovery by $53,436 to $249,121 based on a revised total rate case expense of $1,245,607 (Exh. NG-RRP-2, at 22 (Rev. 3)). Based on our findings above, the Department accepts a total rate case expense of $1,245,607. We also accept a normalization period of five years, which results in an annual level of rate case expense of $249,121. Accordingly, we need not make any further adjustments to the Company's rate case expense.

J. Amortization of Hardship Protected Accounts

1. Introduction

Hardship protected accounts are residential accounts that are protected from shut-off by the utility for nonpayment. 220 C.M.R. §§ 25.03, 25.05. To qualify for protected status from service termination, customers must demonstrate that they have a financial hardship and meet certain other requirements, such as a household member suffering from a serious illness or residing with a child under twelve months of age. See 220 C.M.R. §§ 25.03(1), 25.03(3), 25.05(3).[168] All qualified accounts are protected from shut-off for nonpayment year round,

[168] An account qualifies for protected status where the customer certifies that the customer has a financial hardship, and: (1) a person residing in the household is seriously ill; (2) a child under the age of twelve months resides in the household; (3) the customer takes heating service between the period November 15th and March 15th, and the service has not been shut off for nonpayment prior to November 15th; or (4) all adults residing in the

except for heating customers with a financial hardship. These heating accounts are protected from shut-off for nonpayment only during the winter moratorium period, November 15th through March 15th. 220 C.M.R. §§ 25.03(1)(a)3, 25.03(1)(b).

The Company states that because hardship protected accounts cannot be disconnected, the accounts remain active and continue to receive service despite slow or non-payment of amounts due (Exh. NG-RRP-1, at 49). Further, the Company notes that if an active hardship protected customer's account balance is in arrears, the Company is prohibited by the Department's regulations from collecting the overdue balance (Exh. NG-RRP-1, at 51). As a result, the active hardship protected customer accounts receivable balances in arrears increase over time (Exh. NG-RRP-1, at 51).

According to the Company, its hardship protected account receivable balance over 360 days[169] was $40,607,637 as of June 30, 2015, the end of the test year (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 24). The Company updated its active hardship protected balance over 360 days throughout the proceedings and reported a balance of $52,027,414, as of July 30, 2016 (Exh. WP-NG-RRP-13 (Rev. 3)). The Company proposes to recover the $52,027,414 over a five-year period, which results in an annual amortization expense of $10,405,483 (Exhs. NG-RRP-2, at 24 (Rev. 3); NG-RRP-8, at 2).

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household are age 65 or older and a minor resides in the household. 220 C.M.R. § 25.03. Customers who are unable to pay an overdue bill and meet the income eligibility requirements for the Federal Low-Income Home Energy Assistance Program are deemed to have a financial hardship. 220 C.M.R. § 25.01(2).

169 That is, hardship protected account receivables overdue for payment more than 360 days.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject National Grid's proposal to recover its hardship account receivable balance over 360 days because: (1) approving the recovery of these balances at this point would effectively write-off the accounts as bad debt before such determination can be made; and (2) eventually the Company will recover these balances either from the hardship customers themselves when they pay their bills or from the other customers through the bad debt expense and cash working capital allowance included in the cost of service (Attorney General Brief at 56). Further, the Attorney General contends that if the Company recovers these balances through rates, it will have no incentive to seek recovery of the balances from delinquent customers (Attorney General Brief at 56).

Alternatively, the Attorney General argues that if the Department approves the recovery of National Grid's hardship account receivables balance, the Department also should adjust the Company's cash working capital allowance to reflect the fact that the balances no longer will affect the revenue lag associated with its cash working capital requirement (Attorney General Brief at 57-58; Attorney General Reply Brief at 33). This alternative argument was addressed in Section VII.C.2.a above.

b. Company

The Company argues that the Department should reject the Attorney General's recommendations and instead approve the recovery of the hardship account receivable balance with no corresponding adjustment to its cash working capital allowance (Company Brief at 57-59; Company Reply Brief at 44-46). In particular, the Company contends that its proposal

is consistent with Department precedent, as it is limited to balances that are in arrears over 360 days and unlikely to be repaid by the account holders (Company Brief at 57-58; Company Reply Brief at 45). According to National Grid, unless its proposal is approved, the Company will be unable to recover the balances as bad debt until the account holders' protected status expires (Company Brief at 58; Company Reply Brief at 45). National Grid maintains that during this time the arrearages will continue to grow and add to the burden of all customers who eventually will be required to bear the costs through the Company's uncollectible expense (Company Brief at 58; Company Reply Brief at 45). Further, the Company rejects the notion that approval of its proposal would provide a disincentive for it to continue collection methods against delinquent customers (Company Brief at 58, citing Tr. 8, at 1375-1377; Company Reply Brief at 45).

Finally, National Grid argues that if its proposal is approved, the Department should not adjust the Company's cash working capital allowance (Company Brief at 58-59; Company Reply Brief at 45-46). This argument was addressed in Section VII.C.2.b above.

3. Analysis and Findings

Under current ratemaking practice, there is no cost of service mechanism for the Company to recover the balance of protected hardship accounts receivable. See D.P.U. 10-70, at 210-211, n.12. Public policy decisions and economic conditions persuade us to consider whether and how to treat these costs. D.P.U. 10-70, at 214. Unlike expenses that may be deferred for recovery in a subsequent rate case, the balance of protected hardship accounts receivable cannot be recovered in rates unless the asset is deemed impaired and written off. D.P.U. 10-70, at 210-211, n.12. However, because a utility's hardship protected accounts remain

active, the utility cannot write off the unpaid balance, and therefore, cannot recover the amounts as bad debt expense on a timely basis. D.P.U. 15-80/D.P.U. 15-81, at 169; D.P.U. 13-90, at 159; D.P.U. 10-70, at 213. Generally accepted accounting principles require that, without probable recovery of outstanding balances, a company must recognize an impairment loss through a charge to its income statement and establish a reserve account on its balance sheet for the impaired asset. D.P.U. 10-70, at 214-215.[170]

To provide for the probability of recovery and to avoid an impairment loss, the Department has permitted utilities to collect through distribution rates an amortized amount of significant protected hardship account receivables balances that are over 360 days past due. D.P.U. 15-80\D.P.U. 15-81, at 171; D.P.U. 14-150, at 236; D.P.U. 13-90, at 166; D.P.U. 10-70, at 219. The Company's protected hardship account receivables balance is in line with the levels experienced by Western Massachusetts Electric Company and Fitchburg Gas and Electric Light Company (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 3, 24 (Rev. 3)). D.P.U. 13-90, at 165 & n.110; D.P.U. 10-70, at 216 n.115, 219. Therefore, for purposes of determining ratemaking treatment for National Grid's active protected hardship account receivables, we find that its test year end balances are significant.

By allowing recovery in these circumstances, the Department seeks to provide for the probability of recovery of these older outstanding balances. In light of the record in this case, we see no reason to depart from this ratemaking treatment (Exh. NG-RRP-1, at 51-53). Based on these considerations, the Department allows National Grid to recover its test year balance of

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170 See Statement of Financial Accounting Standards No. 144.

protected hardship account receivables in the amount of $40,607,637.[171] Accordingly, we deny the Company's proposal to recover $52,027,414.[172]

As noted above, the Company has proposed to amortize recovery of the balance over five years (Exhs. NG-RRP-1, at 36, 49-50; NG-RRP-2, at 24). Amortization periods are determined based on a case-by-case review of the evidence and underlying evidence. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 99 (2009); D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. In this case, we consider the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period. Amortizing the amount of $40,607,637 over five years produces an annual expense of $8,121,527 (Exhs. NG-RRP-1, at 36, 50; NG-RRP-2, at 24). Accordingly, we reduce the Company's proposed cost of service by $2,283,956 ($10,405,483 - $8,121,527).

As noted above, the Company sought to update the protected hardship account receivables balance throughout the course of this proceeding, and after the evidentiary hearings concluded (Exhs. NG-RRP-2, at 24 (Rev. 2), (Rev. 3)). However, the Department typically accepts post-hearing updates related to only a limited set of issues – most notably, updated

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171 Recovery through amortization of protected account receivables balances greater than 360 days past due, which amounts to $40,607,637 as of June 30, 2015, balances the financial considerations of the Company and the bill impacts to ratepayers without hardship protected status. D.P.U. 10-70, at 219.

172 The Department acknowledges that in the recent NSTAR Gas Company base rate case, we approved the recovery of some post-test year protected hardship receivables account balances over 360 days. D.P.U. 14-150, at 236. In that case, however, the record did not provide the test year balance. We find that there was no express intention on the Department's part to change its precedent.

property tax bills and updated rate case expense totals. See, e.g., D.P.U. 93-223-B at 15; Hutchinson Water Company, D.P.U. 85-194-B at 4 (1986); Western Massachusetts Electric Company, D.P.U. 84-25-A, at 10 (1984). The Department does not find it appropriate to extend its post-hearing update practice to include updated protected hardship account receivable balances. Instead, we find that permitting recovery of the test year amount of receivables provides a measure of assurance of recovery of the older outstanding balances.

In addition, we direct the Company to track the accounts included in the balance of hardship protected receivables accounts allowed for recovery so that the associated costs are excluded from recovery through normal bad debt expense. D.P.U. 10-70, at 220. The Company shall credit through the Residential Assistance Adjustment Factor ("RAAF") any subsequent payments made by customers towards balances that the Company has amortized (Exh. NG-RRP-1, at 52). D.P.U. 10-70, at 221. In this regard, the Company shall modify its Residential Assistance Adjustment Provision accordingly. Finally, we direct each distribution company with hardship protected account receivable balances approved for recovery by the Department to provide as part of the initial filing in the company's next base rate case, the following information: (1) a detailed narrative of the company's collection efforts relative to outstanding hardship account balances recovered through amortization since the prior base rate case; and (2) the annual amount of payments made by customers against these hardship account balances since the prior rate case.

K. Amortization of ASC 740 Regulatory Asset

1. Introduction

On July 24, 2013, the Legislature passed An Act Relative to Transportation Finance, St. 2013, c. 46 ("Transportation Finance Bill"). In pertinent part, the Transportation Finance Bill repealed G.L. c. 63, § 52A, which provided for a state franchise tax rate of 6.5 percent for public utility corporations (see Exh. NG-RRP-1, at 46). See also St. 2013, c. 46, § 39. Consequently, utility corporations lost their separate tax status for tax years beginning on and after January 1, 2014, and became subject to the tax rates applicable to corporations pursuant to G.L. c. 63, § 39. (Exhs. NG-RRP-1, at 46; AG-2-36; Tr. 6, at 956). For National Grid, the tax rate increased from 6.5 percent to 8.0 percent (Exh. NG-RRP-1, at 46; AG-2-36; Tr. 6, at 956).

National Grid states that the increase in the franchise tax rate created an accumulated deferred income taxes deficiency on the Company's books (Exh. NG-RRP-1, at 46; Tr. 6, at 954-957). As a result, pursuant to Accounting Standards Codification 740 ("ASC 740") (formerly Statement of Financial Accounting Standard No. 109 ("FAS 109")), National Grid recorded an additional $11,907,760 in accumulated deferred income tax liability ($11,717,222 for MECo and $190,537 for Nantucket Electric) (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); DPU-34-6; AG-2-36, Att. 1). The Company proposes to recover the $11,907,760 over a five-year period, which results in an annual deferred income tax amortization expense of $2,381,552 (Exhs. NG-RRP-2, at 32 (Rev. 3); DPU-34-6).

At the same time, the Company proposes to offset the accumulated deferred income tax deficiency with a cumulative deferred tax liability of $14,111,602 associated with a tax basis balance sheet true-up for MECo that also will be amortized over a five year period, which results

in a reduction of $2,822,320 in annual amortization expense (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); AG-2-36-2; Tr. 6, at 957-958). Together, these two adjustments result in a net amortization amount of negative $440,768 ($2,381,552 - $2,822,320), which the Company proposes to record as a reduction to income tax expense (Exhs. NG-RRP-1, at 46; NG-RRP-2, at 32 (Rev. 3); NG-RRP-8, at 8 (Rev. 3); Tr. 6, at 961).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that because the majority of the increase in deferred tax liability was property related, the increase in the deferred tax liability was not payable immediately, and will not be payable over the next five years (Attorney General Brief at 28, citing Exh. AG-DJE-4). Instead, the Attorney General contends that the tax liability will be paid back over the remaining life of the Company's property as that property depreciates (Attorney General Brief at 29). Therefore, the Attorney General asserts that the Company's proposed five-year amortization period is inappropriate because the Company would then recover the increased income taxes more rapidly than they are actually being paid (Attorney General Brief at 29).

The Attorney General argues that consistent with Department precedent, the appropriate amortization period for the plant-related ASC 740 regulatory assets is the estimated remaining service lives of the Company's plant assets (Attorney General Brief at 29, citing D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n. 136; D.P.U. 92-111, at 172-173; Attorney General Reply

Brief at 13-14).[173] The Attorney General points out that the Department recently reaffirmed that it was appropriate to recover deferred tax regulatory assets "over an amortization period reflective of the remaining life of the company's utility plant in service at the time" (Attorney General Brief at 29, citing D.P.U. 14-150, at 241). In addition, the Attorney General argues that the Company has provided no compelling reasons to depart from this precedent for plant-related items (Attorney General Reply Brief at 14).

The Attorney General argues that of the $11,907,760 in increased corporate excise tax, $10,077,661 is plant related and subject to an amortization period based on the remaining life of the Company's net plant in service (Attorney General Brief at 28-29, citing Exh. AG-DJE-1, at 13; Attorney General Reply Brief at 13-14). In this regard, the Attorney General argues that the Company's schedules show that the average remaining life of the Company's net plant in service as of the end of the test year is 18 years (Attorney General Brief at 29, citing Exh. NG-RRP-2, at 27). She states that amortizing the plant-related portion of the ASC 740 regulatory assets over 18 years reduces the Company's annual amortization to $559,870, which is $1,455,662 less than proposed by the Company (Attorney General Brief at 29, citing Exh. AG-DJE-1, Sch. DJE-4). Alternatively, the Attorney General notes that her own analysis of National Grid's average service lives and depreciation accrual rates show that the remaining life of the Company's net plant in service is 21 years, which would reduce the annual amortization of the plant-related portion of the regulatory asset to $479,889 ($10,077,661 ÷ 21) (Attorney General Brief at 30).

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173 The Attorney General accepts the Company's proposed five-year amortization of non-plant related ASC 740 regulatory assets (Attorney General Reply Brief at 13-14).

Regarding the Company's proposed five-year amortization period of MECo's excess deferred income tax balance of $14,111,602, the Attorney General does not contest the Company's proposal (Attorney General Reply Brief at 14).

b. Company

The Company concedes in making its proposal that it was mindful of the Department's recent precedent relating to the amortization period of regulatory assets (Company Brief at 52, citing D.P.U. 14-150; D.P.U. 13-75). However, the Company argues that its proposal is intended to return to ratepayers the deferred tax balance sheet true-up over an accelerated period as opposed to returning the net credit to customers over a longer period as proposed by the Attorney General (Company Brief at 52, citing Tr. 6, at 959-960; Tr. 9, at 1482-1483). Therefore, the Company urges the Department to reject the Attorney General's proposed amortization period (Company Brief at 53).

3. Analysis and Findings

ASC 740 requires companies to recognize on their financial statements all previously unrecorded future income tax liabilities (see Exh. NG-RRP-1, at 46). See also D.P.U. 13-75, at 269; D.T.E. 05-27, at 227. The change in National Grid's state income tax expense arising from the enactment of the Transportation Finance Bill results in deficiencies in the Company's deferred state income tax reserve (Exhs. NG-RRP-1, at 46; AG-2-36). The Department has reviewed the Company's proposal and finds that National Grid may recover a regulatory asset of $11,907,760 as a result of the increase in the franchise tax rate (Exh. NG-RRP-2, at 32 (Rev. 3)).

As noted above, the Company claims that its proposed amortization period of five years is intended to return to ratepayers the deferred tax balance sheet true-up over an accelerated

period as opposed to returning the net credit to customers over a longer period as proposed by the Attorney General (Company Brief at 52, citing Tr. 6, at 959-960; Tr. 9, at 1482-1483). Notwithstanding the Company's argument, however, in the case of a deficiency in a deferred income tax reserve, such as that associated with the change in state income rate as a result of the Transportation Finance Bill, a longer recovery period serves to reduce the annual amortization, thus benefiting customers. More significantly, the Department has found that it is appropriate to recover ASC 740 regulatory assets over an amortization period reflective of the remaining life of the company's utility plant in service at the time, pursuant to the South Georgia method.[174] See, e.g., D.P.U. 14-150, at 241; D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n.136; D.P.U. 95-40, at 50; D.P.U. 92-111, at 172-173; Essex County Gas Company, D.P.U. 87-59, at 55-56 (1987). The Company has provided no compelling reasons to depart from this precedent for plant-related items.

Approximately 15 percent of the Company's accumulated deferred income taxes deficiency, however, is due to non-plant related book tax timing differences, which can be subject to a quicker turnaround than most plant items (Exh. DPU-34-6). The Department finds that it is appropriate to consider the shorter turnaround associated with non-plant related timing differences in determining the appropriate amortization period in this instance. D.P.U. 14-150, at 241-242.

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174 Pursuant to the South Georgia method, accumulated deferred income tax deficiencies resulting from changes in tax rates are recovered on a straight-line basis, by amortizing the deficiency over the remaining regulatory life of the property. D.P.U. 14-150, at 241 n.145. This approach is referred to as the "South Georgia" method because it was first prescribed by the Federal Power Commission in South Georgia Natural Gas Company, FPC RP-77-32. D.P.U. 92-111, at 171 n.49; D.P.U. 87-59, at 55-56.

National Grid's net plant balance as of October 1, 2016 (proximate to the date of this Order) is calculated at $2,307,263,848 (Exh. NG-RRP-2, at 30 (Rev. 3)). Application of the depreciation accrual rates approved in this Order to the respective plant investment account balances produces a depreciation expense of $125,244,314 (see Exh. NG-RRP-2, at 27 (Rev. 3); Section VIII.E.5.e above). Accordingly, we find that the remaining life of the Company's plant is 18.4 years.[175] The Department will calculate a five-year amortization period for the 15 percent of non-plant-related accumulated deferred income taxes, and an 18.4-year amortization period to the 85 percent of plant-related accumulated deferred income taxes, resulting in a total annual amortization period of 16.39 years.[176] Thus, the Department finds that the appropriate amortization period for the Company's ASC 740 regulatory asset is 16 years. Based on the foregoing, the Department approves the Company's recovery of its regulatory asset of $11,907,760 over a period of 16 years. Application of this amortization period to the approved balance produces an annual amortization of $744,235.

Regarding the Company's excess deferred income taxes resulting from MECO's balance sheet true-up, the Department has examined the Company's calculations (Exh. AG-2-36, Att. 2). Based on this review, we find that the Company has properly calculated the excess deferred taxes of $14,111,602. The Department also finds that five years represents a reasonable amortization period applicable to the deferred tax balance sheet true-up. Application of this amortization period to the approved balance produces an annual amortization of negative $2,822,320.

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175 The $2,307,263,848 net plant balance divided by a depreciation expense of $125,244,314 results in a remaining life equal to 18.4 years.

176 (18.4 years x 0.85) + (5.0 years x 0.15) = 16.39 years.

The net effect of these two amortizations is a net unfunded deferred tax liability of negative $2,078,085. National Grid has included an amortization amount of negative $440,768 in its income tax calculation (Exh. NG-RRP-2, at 31 (Rev. 3)). Accordingly, the Department will reduce National Grid's proposed income tax adjustment by $1,637,317. The effect of this adjustment on the Company's income tax expense is presented in Schedule 8 of this Order.

L. FAS 112 Expense

1. Introduction

FAS 112[177] establishes standards of financial accounting and reporting for the estimated cost of benefits provided by an employer to former or inactive employees after employment but before retirement ("postemployment benefits") (see Exhs. NG-RRP-Rebuttal-1, at 31; DPU-30-3; FAS 112: Employers' Accounting for Postemployment Benefits, an amendment of FASB Statements No. 5 and 43, at 4, found at: http://www.fasb.org/jsp/FASB/Document_C/DocumentPage?cid=1218220123881&acceptedDisclaimer=true ("FAS 112")). Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents (FAS 112, at 4-5).[178] This group includes employees who have been laid off and those on disability leave, regardless of whether they are expected to return to active status (FAS 112, at 5). National Grid states that

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177 In 2009, as part of a general recodification of the Financial Accounting Standards Board's accounting rulings, FAS 112 became part of ASC 712 (see Exh. NG-RRP-Rebuttal-1, at 31).

178 More specifically, postemployment benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage (FAS 112, at 5).

because these expenses are volatile and impacted by the actuarial assumptions used to arrive at the annual expense accrual, the Company normalizes the costs based on an historical average level (Exh. NG-RRP-1, at 22).

During the test year, National Grid booked a negative $2,258,474 in FAS 112 expense (Exh. NG-RRP-2, at 14).[179] However, the Company books annual FAS 112 expenses based on a five-year average expense (Exhs. NG-RRP-1, at 22; NG-RRP-2, at 14; NG-RRP-Rebuttal-1, at 31). In its initial filing, National Grid reported that the most recent five-year average expense charged to O&M was $495,065, which comprised the period commencing with the Company's fiscal year ended March 31, 2011 through its fiscal year ended March 31, 2015 (Exhs. NG-RRP-1, at 22; NG-RRP-2, at 14; NG-RRP-Rebuttal-1, at 31). As such, the Company proposed a normalizing adjustment of $2,753,539 (Exh. NG-RRP-2, at 14). As discussed further below, in response to issues raised by the Attorney General, the Company revised its five-year average FAS 112 expense to $78,733 (Exhs. NG-RRP-2, at 14 (Rev. 3); WP-NG-RRP-7 (Rev. 1)). This revised total represents a reduction of $416,331 from the $495,065 five-year average FAS 112 expense charged to O&M in the initial filing (Exh. NG-RRP-2, at 14 (Rev. 3)). Because its test year FAS 112 expense was a negative $2,258,474, the Company now proposes a revised normalization adjustment of $2,337,208 (Exh. NG-RRP-2, at 14 (Rev. 3)).

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179 The Company attributes the negative FAS 112 expense to significant gains realized as a result of an increase in the discount rate, favorable claims experience, and a reduction in long-term disability income replacement claimants (Exh. DPU-30-6).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company should revise its FAS 112 expense in two ways: (1) update the average expense to include fiscal year 2016 expense; and (2) use a four-year expense average instead of a five-year average (Attorney General Brief at 36-38). Regarding the first revision, the Attorney General notes that including fiscal year 2016 expense in the FAS 112 calculation would capture a portion of the Company's test year expense (Attorney General Brief at 36). She points out that the Company agrees to this revision (Attorney General Brief at 36).

Regarding the second revision, the Attorney General argues that it is appropriate to exclude from the FAS 112 calculation the expense associated with fiscal year ended 2012 because the Company's external actuarial firm revised the method used in determining the FAS 112 expense beginning with the fiscal year ended March 2013 (Attorney General Brief at 37, citing Exhs. NG-RRP-7, at 12, 51; AG-DR-1, at 19). The Attorney General contends that the use of fiscal years prior to the change in methodology would produce results that are inconsistent with the current method used by the actuarial firm (Attorney General Brief at 37). Thus, she asserts that the normalized FAS 112 expense should be based on the most recent four-years of actuarially determined expense levels instead of a five-year average in order to exclude the effects of the prior method and allow for a more consistent comparison of expense levels (Attorney General Brief at 37-38, citing Exh. AG-DR-Rebuttal at 10).

According to the Attorney General, normalizing the FAS 112 expense based on the most recent four years of actuarial evaluations results in a FAS 112 expense of a negative $427,748

(Attorney General Brief at 38, citing Exhs. AG-DR-1, at 20: AG-DR-2, Sch. 5). The Attorney General asserts that, while this approach would result in a negative amount of FAS 112 expense in rates, the expense is representative of the Company's recent experience (Attorney General Brief at 38).

b. Company

The Company agrees that its FAS 112 expense should be revised to include the most recent financial information associated with fiscal year 2016 (Company Brief at 46, citing Exhs. NG-RRP-Rebuttal-1, at 32; NG-RRP-Rebuttal-5). However, the Company disagrees with the Attorney General's recommendation to exclude fiscal year 2012 FAS 112 expense data and to normalize the FAS 112 expense based on the most recent four years of actuarially determined expense levels (Company Brief at 46-49). In particular, the Company contends that the Attorney General misunderstands the impact of the change in method used to calculate the FAS 112 (Company Brief at 47-48). The Company notes that the changes in the method used to calculate FAS 112 expense only have the effect of increasing FAS 112 costs, and maintains that had these changes been incorporated in the fiscal year 2012 valuations, then the cost for that year could only be higher (Company Brief at 47-48, citing Exh. NG-RRP-Rebuttal-1, at 33). Further, according to the Company, adopting the Attorney General's recommendation would result in the inclusion of a negative FAS 112 expense in rates, and thus inappropriately would presume that the Company is earning revenues from its FAS 112 obligations that get passed back to customers (Company Brief at 49). The Company argues that, while FAS 112 expense can be negative from time to time, it is normally a positive expense (Company Brief at 49).

Instead, the Company maintains that the FAS 112 expense should be based on the most recent five years of actuarial data for fiscal years 2012 through 2016, which would result in a five-year average FAS 112 expense of $78,733 (Company Brief at 46, citing Exh. WP-NG-RRP-7 (Rev. 1)). The Company notes that this revised total represents a reduction of $416,331 from the $495,065 five-year average FAS 112 expense charged to O&M in the initial filing (Company Brief at 46, citing Exhs. NG-RRP-7 (Rev. 1); NG-RRP-2, at 14 (Rev. 2)). The Company asserts that because its test year FAS 112 expense was a negative $2,258,474, a revised normalization adjustment of $2,337,208 is appropriate (Company Brief at 46).

3. Analysis and Findings

The Company's FAS 112 expenses are volatile in nature, as they are affected by the actuarial assumptions employed to arrive at the annual expense level (Exhs. NG-RRP-1, at 22; DPU-30-5). These assumptions include the discount rate, mortality, termination rates, disablement rates for active employees, cost of medical coverage, and health care cost trend rates (Exh. DPU-30-4). Consequently, it is reasonable to normalize FAS 112 costs based on an historical average level. See, e.g., D.P.U. 09-39, at 146-149.

In evaluating the Company's proposed adjustment to its FAS 112 expense, we find that it is appropriate for the Company to include in the calculation actuarial data from the most recent fiscal year (i.e., 2016). Further, we are not persuaded by the Attorney General's arguments that it is necessary to revert to a four-year average expense by excluding fiscal year 2012. The Attorney General focuses on the following changes in the method used by the Company's external actuarial firm in determining the FAS 112 expense:

> A change in the accrual method for those groups with benefits that accumulate over a given period (i.e., those with benefits that vary based on a specific age/service criteria). Previously, liabilities for future disableds beyond the current fiscal year were not considered in the valuation for these groups. Our valuation now includes a liability for the expected future disableds for benefits that accumulate over the specific age/service period.
>
> A discount rate assumption that is specific to the shorter duration of the [FAS 112] obligations rather than using the same discount rate used for the company's pension and postretirement medical/life insurance plans.

(Exh. NG-RRP-7, at 12).

While we acknowledge the Attorney General's concerns regarding the change in the way FAS 112 expenses are calculated, we find that the change in accounting for future disabled employees and the use of a lower discount rate would generate a higher liability, and consequently result in higher FAS 112 costs (Exh. NG-RRP-Rebuttal-1, at 33-34). Thus, the exclusion of fiscal year 2012 FAS 112 expenses would skew the overall calculation and produce an average expense that is not representative of the Company's actual FAS 112-related activity.

We conclude that the Company's FAS 112 expense should be calculated based on a five-year average, taking into account fiscal year 2012 through fiscal year 2016. The five-year average expense charged to O&M during this period was $78,733 (Exhs. NG-RRP-2, at 14 (Rev. 3); WP-NG-RRP-7, at 1 (Rev. 1)). As noted above, the Company's test year FAS 112 expense was a negative $2,258,474 (Exh. NG-RRP-2, at 14 (Rev. 3)). Accordingly, we accept the Company's revised normalization adjustment of $2,337,208.

M. Corporate Aircraft Expense

1. Introduction

NGSC provides aviation operations support to its affiliates through its ownership of a 1999 Beechcraft Model 1900D aircraft ("airplane") (Exhs. AG-1-54; AG-1-92, Att. 1, at 15).[180] The Company is allocated a portion of the total expenses associated with the airplane, based on a general allocator consisting of equally weighted ratios of net plant, net margin, and net O&M expenses (Exh. AG-22-10, Att.).[181] During the test year, National Grid was allocated $254,348 in O&M expenses relative to the airplane and its hangar facility located in Syracuse, New York, $82,079 in depreciation expense for the airplane,[182] and $51,060 in airport property taxes, for a total expense of $387,487 (Exhs. AG-22-10; AG-25-19, Att.; AG-25-20, Att.). The Company proposes to decrease its test year cost of service by $7,138 to reconcile the difference between the booked depreciation expense of $82,079, and the calculated depreciation expense of $74,941, based on the allocation factors in use during the test year (Exhs. NG-RRP-2, at 5 (Rev. 3); AG-1-29, Att. at 1; AG-22-10; AG-25-20).

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180 NGSC also owns a 1985 Bell 206L-3 helicopter and a 2014 Bell 429 helicopter (Exh. AG-1-54). Because these helicopters are used exclusively in support of National Grid USA's non-Massachusetts jurisdictional companies, the Company is not allocated any of their associated costs (Exh. AG-25-20).

181 MECo and Nantucket Electric were allocated a combined 18.37 percent of the total airplane-related expenses during the last half of 2014, and a combined 19.04 percent during the first half of 2015 (Exh. AG-22-10, Att.).

182 The Company records depreciation on assets held by the service company as rent expense (Exhs. AG-1-29, Att.; AG-1-92; AG-25-20).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has failed to justify either the need for or the expenses associated with its airplane (Attorney General Brief at 60). She notes that the Department has previously excluded from a utility's cost of service expenses associated with aircraft and other vehicles that were found to be unreasonable (Attorney General Brief at 60, citing D.P.U. 13-75, at 225-226; Fall River Gas Company, D.P.U. 750, at 15 (1982); D.P.U. 18571/18572, at 12-13). The Attorney General recommends that the Department eliminate all test year costs relative to the airplane, and reduce the Company's test year cost of service by $387,486 (Attorney General Brief at 60).[183]

b. Company

National Grid defends its inclusion of airplane-related expenses in its proposed cost of service.[184] The Company notes that National Grid USA has operating companies in Massachusetts, New York, and Rhode Island, as well as a centralized service company providing services to these operating companies (Company Brief at 67-68). In this regard, National Grid maintains that employees providing service to multiple companies must travel to the various states for work-related reasons,[185] and that such out-of-state travel that directly or indirectly

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183 The difference between the Attorney General's proposed reduction and National Grid's test year expense is due to rounding.

184 The Company emphasizes that costs related to the two helicopters have been excluded from the proposed revenue requirement (Company Brief at 67, citing Exhs. AG-1-54; AG-22-10).

185 For example, the Company notes that three of its witnesses in this proceeding are New York-based NGSC employees who had to travel to Massachusetts in order to perform

affects Company operations is undertaken for the benefit of ratepayers and, therefore, is a reasonable expense (Company Brief at 67-68, citing D.P.U. 13-75, at 225).

Further, the Company contends that the Department has recognized that the use of corporate aircraft provides a cost-effective means of traveling for entities that have operating companies in multiple jurisdictions, and that it is reasonable and appropriate to allocate some aircraft expenses to an operating company (Company Brief at 68, citing D.P.U. 13-75, at 225 (2014); D.P.U. 12-25, at 263; D.T.E. 05-27, at 232).[186] Consequently, National Grid concludes that the Department should reject the Attorney General's recommendation and include the full amount of the airplane costs in the Company's cost of service (Company Brief at 68).

3. Analysis and Findings

The Department recognizes that out-of-state travel for business meetings that directly or indirectly affect a utility's operations can be considered to have been made for the benefit of the Company's customers, and thus reasonable expenses associated with such travel are allowable for ratemaking purposes. D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; D.T.E. 05-27, at 233; D.P.U. 92-111, at 154. Further, the Department has found that the use of lease and charter jets provide a cost-effective means of travelling throughout a utility's multi-state operating territory. D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; D.T.E. 05-27, at 232. However, the Department has

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their duties relative to this proceeding (Company Brief at 68, citing Exhs. NG-MPH-1, at 1; NG-DJD-Rebuttal-1, at 1).

186 National Grid analogizes the allocation to the Company of certain aircraft expenses to the allocation of a portion of NiSource Corporate Service Company's airplane costs to Bay State Gas Company which were previously reviewed and approved by the Department in D.P.U. 13-75, at 225; D.P.U. 12-25, at 263; and D.T.E. 05-27, at 232 (Company Brief at 68).

excluded from cost of service vehicles and vehicle-related expenses when use of those vehicles was found to be unreasonable. D.P.U. 750, at 15; D.P.U. 18571/18572, at 12-13.

In the instant case, National Grid shares in the costs associated with the airplane, which is used by employees conducting Company-related business (Exh. AG-1-54). Therefore, it is reasonable to allocate some of the airplane expenses to the Company.

The Department has examined both the airplane-related billings and the allocation formulas used to allocate airplane costs to the Company (Exhs. AG-1-92; AG-22-10; AG-25-20). Although other ways could be devised to allocate the airplane costs among National Grid USA's affiliates, the existence of other possible allocation outcomes does not render the Company's allocation method invalid. D.T.E. 03-40, at 204; Commonwealth Electric Company, D.P.U. 88-135/151, at 83 (1989). Based on our review, the Department finds that the method used to allocate the airplane expenses to National Grid is reasonable, is provided at cost, and produces both cost-effective and nondiscriminatory results for the use of the airplane by the Company.

N. NGSC Allocations

1. Introduction

NGSC provides services to National Grid in thirteen functional areas: audit, corporate affairs, customer, finance, human resources, information systems, legal, network strategy, operations, procurement, regulation and pricing, shared services, and strategy, business development and technology (Exh. DPU-25-18, Att.).[187] The Company incurs expenses from

[187] Some employees that provide services to National Grid affiliates are categorized as "other affiliate employees," but these employees provide services to National Grid affiliates akin to service company employees (Exh. DPU-28-7). For example, employees

NGSC in two ways: (1) through direct charges, which are billed to National Grid for costs incurred by NGSC employees directly related to the Company; and (2) through common costs, which are allocated among the affiliates that receive the services provided by NGSC, based on allocation factors and billing pools (Exh. NG-RRP-1, at 12). National Grid included in the test year NGSC charges in their respective expense categories included in the cost of service (e.g., salary and wages) (Exhs. NG-RRP-1, at 12; NG-RRP-2, at 6, 9 (Rev. 3)). Additionally, the Company included NGSC charges in the normalizing or known and measurable adjustments to the cost of service in their respective expense categories (e.g., the proposed adjustment of $3,456,591 to salary and wage expense for service company employees is included in the total proposed $8,966,172 adjustment to salary and wage expense) (Exhs. NG-RRP-1, at 12; NG-RRP-2, at 6, 9 (Rev. 3)). In the test year, the Company incurred $201,513,353 of O&M expenses originating from NGSC (Exh. DPU-4-4, Att.). National Grid proposes $15,437,187 in pro forma adjustments to NGSC-related test year expenses (Exh. DPU-4-7).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that there is little management accountability regarding service company costs, including control of the costs, and the effect of those costs on customers

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in National Grid's US Services Delivery Center ("SDC"), which supports human resources, procurement, customer, and finance processes, are employees of Niagara Mohawk Power Corporation ("Niagara Mohawk"), but allocate their time to other National Grid affiliates, including the Company, based on services the SDC employees provide to the various affiliates (Exh. DPU-28-7; RR-DPU-3). The SDC employees are primarily unionized workers, and their collective bargaining agreement is between their union and Niagara Mohawk (RR-DPU-3). Therefore, although these employees are not categorized as service company employees, their work time and associated costs are allocated in a similar manner as service company employees (Exhs. DPU-12-12; DPU-28-7; RR-DPU-3).

(Attorney General Brief at 2, citing RR-AG-1, Att.). According to the Attorney General's calculations, NGSC charges to the Company grew 71.26 percent, or 9.38 percent per year on average, from 2008 to 2014 (Attorney General Brief at 2, citing Exh. AG-KC-1, at 4). The Attorney General contends that this growth in costs is greater than the rate of inflation and the average growth rate of the median household income in Massachusetts over the same period (Attorney General Brief at 2, citing Exh. AG-KC-1, at 4-5). Further, the Attorney General claims that the increasing service company costs partially explain the increase in the Company's proposed cost of service (Attorney General Brief at 2). As a result, the Attorney General asserts that the Department should limit the costs allowed to be recovered from customers in this case[188] (Attorney General Brief at 3).

b. Company

National Grid argues that the NGSC charges are reasonable and properly allocated to the Company (Company Brief at 91). Therefore, National Grid recommends that the Department approve the NGSC charges included in the Company's cost of service (Company Brief at 91-92).

3. Analysis and Findings

a. Introduction

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and

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188 The Attorney General suggests that one solution is modifying National Grid's rate recovery mechanisms to incentivize the Company to minimize costs (Attorney General Brief at 3). The Attorney General claims that the Company's current reconciling rate mechanisms provide a perverse incentive for the Company to earn more as spending increases (Attorney General Brief at 3). The Department addresses National Grid's rate recovery mechanisms in Sections V and VI.

(3) allocated to the utility by a method that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 13-75, at 184; D.P.U. 12-25, at 231; D.P.U. 89-114/90-331/91-80 (Phase I) at 79-80; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). In addition, 220 C.M.R. § 12.04(3) provides that an affiliated company may sell, lease, or otherwise transfer an asset to a distribution company, and may also provide services to a distribution company, provided that the price charged to the distribution company is no greater than the market value of the asset or service provided.

b. Services

In determining whether the services rendered by an affiliate specifically benefit a regulated utility and do not duplicate services already provided by the utility, it is necessary to examine whether there is any overlap between the services rendered by an affiliate and the operating company's functions. D.P.U. 13-75, at 184; D.P.U. 08-27, at 80-81; Oxford Water Company, D.P.U. 1699, at 11-12 (1984). Within the 13 functional groups, services provided by NGSC to the Company include: accounting, payroll, auditing, finance/business planning, business continuity and emergency response, communications, human resources, engineering, transmission construction, corporate and corporate records, risk management, and management, environmental, insurance, tax, legal, treasury, regulatory, energy efficiency services, facilities, information technology, customer relations, and other various functions (Exh. DPU-1-25, at 1-2; see Exh. DPU-25-18, Att.). The Company does not have employees who perform these tasks

(Exh. DPU-1-25, at 2). Therefore, these activities specifically benefit National Grid, and there is no overlap between the services rendered by NGSC and the Company's functions.

c. Price

Next, we evaluate whether NGSC charges to National Grid were at a competitive and reasonable price. In prior cases, when determining whether services were charged at a competitive and reasonable price, the Department has accepted a review of employer compensation structures, compared to the market, because service company charges tend to be primarily labor-related.[189] D.P.U. 13-75, at 186; D.P.U. 12-25, at 233; D.P.U. 09-39, at 260. Regarding a review of National Grid's compensation structures, the Company's proposal shows that it established a salary range for each band of non-union employees that is competitive with the median market rate (Exhs. NG-MPH-1, at 12; NG-MPH-1; DPU-8-24). Moreover, NGSC labor is charged to the Company at cost and does not include a profit that would be charged by an outside vendor (Exhs. DPU-1-25, at 2; DPU-25-13, at 1).

In addition to comparing service company compensation to that of the market, National Grid provided additional evidence of the competitiveness and reasonableness of NGSC costs. In particular, the Company developed external cost comparisons to demonstrate that NGSC costs are reasonable relative to the corresponding market alternatives (Exh. DPU-25-13, at 2). For two-thirds of service company functions, external cost comparisons show that the services provided by NGSC compare favorably to third-party rates obtained through the market

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189 The Company acknowledges that the primary costs (i.e., more than 50 percent of total costs) allocated to the Company from NGSC are labor and labor-related costs associated with employees performing the functions that are provided on a shared basis (Exh. DPU-1-25, at 2). NGSC allocated or directly charged $73,393,666 in test year salary and wages to the Company (Exh. NG-RRP-2, at 9 (Rev. 3)).

(Exhs. DPU-25-13, at 2; DPU-25-19, Att. & Att. (Supp.)).[190] National Grid's analysis also shows that the vast majority of services performed by NGSC for the Company are provided at a lower cost than an outside vendor (Exhs. DPU-25-13, at 2; DPU-25-19, Att. & Att. (Supp.)).

The Department has previously noted that, in order for reimbursed costs associated with overseas employees of National Grid plc to be recovered through rates, such costs must benefit Massachusetts customers, be reasonable, and be prudently incurred. D.P.U. 10-55, at 455-456 (2010).[191] Since its last rate case, the Company modified its accounting of non-business related expatriate expenses (Exh. DPU-1-25, at 3). Specifically, a third-party vendor in the United Kingdom now manages non-business related expenses incurred by expatriate employees (Exh. DPU-1-25, at 3). All non-business related expenses are: (1) reviewed and approved before the expatriate employee is reimbursed by the third-party vendor; (2) charged to the parent company; and (3) borne by shareholders (Exh. DPU-1-25, at 3). Business-related expatriate expenses are charged through the normal employee expense reimbursement system

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190 Pursuant to a settlement agreement between the Company and the Attorney General in Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-155-A (2014), one-third of external cost comparisons (i.e., corporate affairs; human resources; network strategy; safety, health, and wellness; and shared services), were developed as of March 31, 2015 (Exh. DPU-25-19, Att.). D.P.U. 10-155, Settlement Agreement at § 5. One-third (i.e., customer; information services; operations (including operations support, emergency planning, project management & complex construction, and process excellence); and strategy, business development and technology) were developed as of March 31, 2016 (Exh. DPU-25-19, Att. (Supp.)). The final third of remaining functions (i.e., audit, finance, legal, procurement, and regulation and pricing) will be developed by March 31, 2017 (Exh. DPU-25-19).

191 Reimbursed costs include moving costs, house rentals, annual vacations to the employee's home country, and health insurance costs that exceed those covered by the employee's home country health insurance.

(Exh. DPU-1-25, at 3). Based on the foregoing, the Department finds that the NGSC expenses charged to National Grid were charged at a competitive and reasonable price.

d. Allocation

Finally, we evaluate the method of allocating costs from NGSC to National Grid. When allocating costs among affiliates, it is preferable that costs associated with a specific utility are directly assigned to that utility. In the absence of a clear relationship between the cost and the affiliate, or when costs cannot be directly assigned, these costs are preferably allocated using cost-causative allocation factors to the extent such allocation factors can be applied, with general allocation factors used to allocate any remaining costs. D.P.U. 13-75, at 188; D.P.U. 11-01/D.P.U. 11-02, at 318-321; D.P.U. 10-114, at 271-274.

As previously stated, NGSC charges are charged directly to the Company, or when direct assignment is not possible, through allocation factors (Exh. NG-RRP-1, at 12). To ensure accuracy of the allocations, the Company requires employees to attend an in-depth enterprise-wide training program so that they charge their time and expenses appropriately (Exh. DPU-1-25, at 2). Further, all service company employees are required to take computer-based allocation training, and refresher training annually, developed and maintained by the Cost Allocations Compliance ("CACP") team (Exh. DPU-1-25, at 2). The CACP team also maintains and updates National Grid's cost allocation manual ("CAM"), which is stored on the Company's intranet and is readily accessible to all employees (Exh. DPU-1-25, at 3). The CAM explains the methods of allocating service company costs (Exh. AG-1-92). National Grid provided detailed information on all allocation codes and the metrics used to calculate them

during the test year (see Exh. AG-1-92, Atts. 2 & 3).[192] The Department has reviewed these allocation codes and metrics and finds them to be cost-effective and nondiscriminatory.

It is the Company's policy to review all new service company internal requisitions for the appropriateness of the allocations prior to it being set up in SAP (Exh. DPU-1-25, at 3). Moreover, the service company accounting and finance employees circulate monthly reports of service company costs to each of the jurisdiction (e.g., Massachusetts) finance teams, who will review the appropriateness of those costs allocated or direct charged to each individual company within their jurisdiction (Exh. DPU-1-25, at 3). Additionally, the Company investigates variances greater than ten percent of the prior year's monthly bill (Exh. DPU-1-25, at 3). Further, National Grid reviews invoices from the service company that are greater than $10,000 to determine that the costs benefit the Company, and that the allocation is appropriate (Exh. DPU-1-25, at 3).

Additionally, as noted above in Section III, the Company retained PwC, an independent public accounting firm, to assist with the review of the costs charged from NGSC to National Grid in the test year (Exh. NG-RRP-1, at 7). PwC concluded that the costs were recorded accurately, and, on a net basis, that the costs were allocated appropriately pursuant to the Company's CAM (Exh. NG-RRP-1, at 10; NG-RRP-3).

4. Conclusion

Based on the foregoing, we find that National Grid has sufficiently demonstrated that the service company allocations are: (1) for activities that specifically benefit the Company and that

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192 These codes are updated at the beginning of each fiscal year (or when there is a significant change in the business) based on the prior calendar year numbers (Exh. AG-1-92).

do not duplicate services already provided by National Grid; (2) made at a competitive and reasonable price; and (3) allocated to the Company by a method that is both cost-effective and nondiscriminatory. Other sections of this Order address issues related to NGSC costs specific to those categories of costs.

O. Information Systems and Facilities Lease Expense

1. Introduction

a. Overview

National Grid's information systems ("IS") and facilities rent expenses represent charges billed to the Company for computer and information systems and leased facilities provided by NGSC (Exh. NG-RRP-1, at 20, 31-32).[193] NGSC owns the IS assets and bills its affiliated companies, including MECo and Nantucket Electric, their respective pro-rated share of costs including depreciation and a return component (Exhs. NG-RRP-1, at 31-32; NG-RRP-2, at 15). Additionally, NGSC bills the Company for use of facilities in Northborough[194] and Waltham, along with other Massachusetts locations, as well as for facilities in New York, Rhode Island, and Washington, D.C. (Exhs. NG-RRP-2, at 15; AG-2-24; DPU-31-23; DPU-31-24).[195] NGSC

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193 The Company refers to capital recovery-type charges associated with leased facilities and NCSC's IS investments as "asset recovery charges" (Exh. NG-RRP-2, at 15 (Rev. 3)). In this Order, we use the term "rent" for ease of reference.

194 Although MECo owns the Northborough facility, the facility is shared with other affiliates. Thus, the total costs related to the site are initially billed to NGSC, which then allocates those total costs to the operating entities sharing use of the facility (Exh. DPU-31-24).

195 There are corporate offices, government relations offices, and operations centers located in New York, Rhode Island, and Washington, D.C. (Exh. AG-2-24). The Company has removed $49,780 in costs associated with the Washington, D.C. office on the basis that

allocates both IS and facilities costs using a coding system that apportions the costs by an affiliate's percentage share of expenses or use of space measured in square feet (Exhs. NG-RRP-4, at 4; WP-NG-RRP-8; DPU-31-19; DPU-31-20; DPU-31-23; AG-1-92; AG-15-18; Tr. 5, at 603).

NGSC uses various methods for calculating rental charges for various facilities and information systems (Exh. AG-11-2, Att. at 1-17). Depending upon the particular facility and information system, NGSC will allocate their associated costs among its affiliates based on: (1) direct assignment; (2) a three-point allocation system; (3) customer counts; (4) cost causation; and (5) in the case of the Sutton warehouse,[196] a weighted average cost calculation of historical inventory (Exhs. NG-RRP-4, at 3-5; DPU-14-6; DPU-31-16; DPU-31-19; DPU-31-20; DPU-31-23; DPU-31-24; AG-1-92, Att. 1, at 29; AG-11-2; AG-11-3).[197]

b. SAP Consolidation Program

IS rent in the instant case is associated with new and enhanced information technology ("IT") assets upgraded as part of a larger IS consolidation and modernization conducted by National Grid USA starting in 2010 and affecting all National Grid USA affiliates

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this facility is primarily used for government relations, including lobbying activities (Exh. WP-NG-RRP-8, at 1).

196 The Sutton warehouse is National Grid's New England Distribution Center on the Sutton/Northbridge town line (Exh. DPU-14-6). See also, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 10-112-A at 2 (2013).

197 The Company's three-point allocation method employs data on net margin, net plant, and O&M expense to apportion expenses to the various operating companies (Exhs. AG-1-92, Att. 1, at 29; AG-11-2; AG-11-3; DPU-31-16; DPU-31-19; DPU-31-20).

(Exhs. NG-MLR-1, at 26-27; NG-RRP-1, at 32; Tr.1 at 46-49; Tr. 5, at 577-578).[198] Under the project name U.S. Foundations Program ("USFP") and employing an SAP Enterprise Resource Planning platform, NGSC sought to consolidate multiple legacy technology platforms brought together by the acquisition of KeySpan in August 2007 (Exhs. NG-MLR-1, at 26-27; AG-4-4; Tr. 5, at 577-578).[199] Both capital project costs and ongoing maintenance costs for new and enhanced data management systems deployed for outage management, finance, performance reporting, and other business processes such as payroll, supply chain, and IT delivery are included in the rent charge (Exh. NG-RRP-4, at 1-2; Tr. 5, at 597).

2. Company Proposal

a. Introduction

During the test year, National Grid booked $31,651,504 in facilities and IS lease expense, consisting of $9,031,383 in facilities rent expense, $1,357,905 in NGSC charges associated with depreciation and a return on facilities, and $21,262,215 in IS rent and operating charges (Exh. NG-RRP-2, at 15 (Rev. 3)).[200] The Company proposes to recover a total of $38,519,355 for facilities and IS expenses incurred during the test year and through the end of the rate year, September 30, 2017 (Exh. NG-RRP-2, at 15 (Rev. 3)).[201] The Company's proposal to increase

198 The IS consolidation project required approval from the board of directors of National Grid plc but was managed by National Grid USA (Exhs. AG-4-4; Tr. 5, at 571-572).

199 The Company launched the initial USFP modules in November 2012, but problems with implementation prompted a corrective stabilization program that ran until September 2014 (Exhs. NG-MLR-1, at 27-28; AG-4-20).

200 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

201 Of this amount, $29,732,078 represents IS lease expenses and $8,787,277 is associated with facilities lease expense (Exh. NG-RRP-2, at 15 (Rev. 3)).

facilities and IS lease expense is based on what the Company represents are known and measurable adjustments of $10,127,504, as discussed below (Exh. NG-RRP-2, at 15 (Rev. 3)).

b. Normalizing Adjustments

The facilities and IS adjustments include normalizing adjustments of $3,259,652, consisting of: (1) a decrease of $1,602,011 for restated test year facilities rental expense; and (2) a decrease of $1,657,641 from the Company's test year share of IS rent billed for NGSC-owned systems in service as of June 30, 2015 and restated to an annual asset recovery amount (depreciation and return) for the rate year ending September 30, 2017 (Exhs. NG-RRP-1, at 20; NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1).[202] These adjustments produced a normalized test year facilities and IS expense total of $28,391,851, consisting of $8,787,277 in facilities lease and depreciation and return expense and $19,604,574 in IS rent expense (Exh. NG-RRP-2, at 15 (Rev. 3)).

c. Post-Test Year IS Adjustments

Along with its proposed test year normalization adjustments, the Company proposed an increase of $10,127,504 for post-test year IS rent charged by NGSC related to the implementation of new data management systems placed into service by May 31, 2016, and their associated ongoing support and maintenance costs (Exhs. NG-RRP-1, at 31-32; NG-RRP-2, at 15 (Rev. 3); Tr. 5, at 596). Of the proposed $10,127,504 increase, $9,026,666 in IS rent expense involves NGSC capital additions and enhancements for the rate year ending September 30, 2017 (Exhs. NG-RRP-1, at 32; NG-RRP-2, at 15 (Rev. 3); NG-RRP-4, at 1-2 (Rev. 1)).

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202 The Company bases its test year normalization adjustment for both facilities and IS rents on a projected average NGSC depreciation balance for a twelve-month period between October 1, 2016 and September 30, 2017 (Exhs. NG-RRP-4, at 3-5; WP-NG-RRP-8, at 2-4; AG-ADR-1, at 25, lines 18-19).

These new systems and enhancements include $5,619,623 associated with a new outage management system ("OMS") placed into service on December 4, 2015; $2,504,315 for the USFP SAP Enhancement One ("EHR1") project, most of which went into service in November 2015; and $902,728 for other IS investments placed into service between October 2015 and May 2016 (Exhs. NG-RRP-4, at 1-2 (Rev. 1); NG-RRP-Rebuttal-1, at 20; NG-RRP-Rebuttal-4, at 1, 6; AG-DR-1, at 22).[203] Additional incremental ongoing operation costs of $574,716 for OMS and $526,122 for the energy management system ("EMS") complete the $10,127,504 total proposed adjustment (Exh. NG-RRP-2, at 15 (Rev. 3); NG-RRP-4, at 1-2 (Rev. 1)).

d. Facilities Lease Expense

As noted above, along with the IS increases, National Grid proposed to recover $9,031,383 in test year facilities rent expense and $1,357,905 in test year NGSC charges associated with depreciation and a return on facilities (Exh. NG-RRP-2, at 15 (Rev. 3)). These expenses are related to office space, control centers, training facilities, and warehouses (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1). The Company leases space for corporate offices, government relations, operations, training, and warehousing at facilities in Boston, Gardner, Monson, Sutton, Uxbridge, and Waltham (Exhs. NG-RRP-2, at 15 (Rev. 3);

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[203] In rebuttal testimony, the Company agreed to exclude from its calculation of rate year IS rental expense the costs for any delayed projects not placed into service by May 31, 2016 (Exh. NG-RRP-Rebuttal-1, at 20). The Company subsequently reduced the rate year IS rental expense by $679,371 for delayed projects, while subtracting an additional $62,834 for costs related to updated USFP EHR1 investment information (Exhs. NG-RRP-Rebuttal-1, at 20 n.8; NG-RRP-Rebuttal-4, at 1; DPU-31-21, Att., at 2).

WP-NG-RRP-8, at 1; DPU-31-23; DPU-31-24; AG-2-24, Att.).[204] The Company also owns a facility in Northborough (Exhs. NG-WP-RRP-8, at 1; DPU-31-24). For the test year ending June 30, 2015, the Company made $1,602,011 in normalizing adjustments, consisting of corrections to various allocations, inflation, and test year true ups of prior year rent expenses (Exhs. NG-RRP-1, at 20; NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8, at 1 and 8; DPU-31-24). Therefore, the Company's adjusted test year amount of facilities lease expense and associated expense is $8,787,277 (Exh. NG-RRP-2, at 15 (Rev. 3)). The Company proposed no post-test year adjustments related to facilities rent (Exh. NG-RRP-2, at 15 (Rev. 3)).

3. Positions of the Parties

a. Attorney General

i. Overview

The Attorney General argues that the Department should: (1) reject the Company's proposal to include post-test year IS adjustments through September 30, 2017; (2) exclude the IS rent expense on NGSC's books associated with IT systems closed to plant in service after the end of the test year; (3) remove incremental expenses associated with post-test year IS additions; (4) remove non-recurring test year EHR1 implementation expenses; (5) reduce the equity return applied to the NGSC IS assets to 7.80 percent; (6) reduce the return on USFP SAP assets to 3.7 percent; and, if the Department ultimately finds it appropriate to include those post-test year additions, (7) incorporate anticipated savings from post-test year IS additions into the Company's cost of service (Attorney General Brief at 40, 126; Attorney General Reply Brief

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204 The Company breaks down the total facilities cost as follows: $3,308,931 for Reservoir Woods in Waltham; $1,462,878 for Northborough; and $4,015,468 for all other facilities (Exh. NG-RRP-2, at 15 (Rev. 3)).

at 71).[205] The Attorney General did not comment on brief about the Company's facilities expense.

ii. Test Year IS Expenses

The Attorney General argues that it is inappropriate to include IS rent expense charges associated with NGSC's net plant in service and associated accumulated deferred income taxes balances for the post-test year period ending September 30, 2017, as proposed by the Company (Attorney General Brief at 41). She argues that no compelling reason exists in the instant case to calculate the charges to the Company from NGSC for NGSC's recovery of and return on its assets based on a period that extends 15 months beyond the end of the test year (Attorney General Brief at 41).

The Attorney General rejects any notion that excluding the post-test year IS rent expense will create a significant shortfall in the Company's rate recovery and cause the potential loss of more than half of its IS investment (Attorney General Reply Brief at 19). According to the Attorney General, the Department's denial of recovery of post-test year investments would not be unreasonable or unfair because after the end of the test year, the investments in service during the test year continue to be depreciated while the post-test year increase in the accumulated depreciation would not be subtracted from rate base (Attorney General Reply Brief at 19). Additionally, the Attorney General contends that even though some projects may be retired from service after the test year end, they would remain in rate base (Attorney General Reply Brief

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[205] In her original brief, the Attorney General proposed reducing the ROE associated with IS assets from the 10.5 percent ROE incorporated in the Company's original filing to 8.50 percent (Attorney General Brief at 40). Subsequently, the Attorney General recommended setting the allowed ROE at 7.80 percent (Attorney General Brief at 126, citing Exhs. AG-JRW-1, at 51 and 60–61; Attorney General Reply Brief at 71).

at 19). Therefore, the Attorney General recommends that the Department reject the Company's proposal to extend the net balance of NGSC IT assets in place at the end of the test year through the twelve-month period ending September 30, 2017 (Attorney General Brief at 42).

iii. Post-Test Year IS Additions

The Attorney General also opposes the inclusion of any post-test year IS plant in the computation of National Grid's IS expense (Attorney General Brief at 41-42). The Attorney General notes that the Department generally does not recognize post-test year additions to rate base, unless the utility demonstrates that the additions are significant relative to the test year-end rate base (Attorney General Brief at 41, citing D.P.U. 14-150, at 43-44). The Attorney General contends that the Company presents no argument or evidence supporting a change to the cited precedent (Attorney General Brief at 42).

The Attorney General argues that the Company's post-test year IS plant additions represent only a small fraction of NGSC's total IS investment used by the Company (Attorney General Brief at 42; Attorney General Reply Brief at 16-18). In support of her contention, the Attorney General notes that MECo was allocated 18.58 percent and Nantucket Electric was allocated 0.27 percent for their respective portions in the majority of projects included in NGSC's total $145.67 million post-test year IS investment (Attorney General Brief at 42; Attorney General Reply Brief at 18). Thus, she claims that the amount ultimately allocated to the Company through the NGSC IS rental expense is insignificant when compared to the Company's $2.3 billion of net plant and $1.79 billion requested rate base in the instant case (Attorney General Brief at 43; Attorney General Reply Brief at 18). The Attorney General maintains that when determining the significance of a post-test year adjustment, a company's

rate base, not the amount of rate base or investment held by an affiliated entity, is the relevant factor (Attorney General Reply Brief at 17).[206]

Moreover, the Attorney General argues that the 13 separate projects comprising the relevant plant additions are individually insignificant when compared to the Company's rate base (Attorney General Brief at 43). The Attorney General notes that Department precedent considers individual plant investments and not combined plant additions in determining substantive impact on rate base (Attorney General Reply Brief at 17). She asserts that the Department should not allow the Company to obscure the purity of the test year by introducing post-test year investments of an affiliated entity against well-established Department precedent for the limited consideration of post-test year plant additions in rates (Attorney General Reply Brief at 18).

Consequently, the Attorney General recommends that the Department exclude the entire $9,026,666 in post-test year NGSC IT plant additions placed into service between October 2015 and May 2016 from the calculation of IT expenses (Attorney General Brief at 42).[207]

iv. Incremental OMS Expense

The Attorney General notes that National Grid seeks to include $574,716 in projected operating expenses associated with the OMS implemented by NGSC after the end of the test year (Attorney General Brief at 44, citing Exh. NG-RRP-2, at 15). Consistent with her proposed

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206 The Attorney General notes that the Company instead limits its comparison of the post-test year IS plant additions to NGSC's total net investment in IS systems (Attorney General Reply Brief at 17).

207 During the proceedings, the Attorney General offered an alternative set of adjustments in the event that the Department allowed post-test year NGSC plant additions (Exhs. AG-DR-1, at 41-48; AG-DR-3, Schs. 1-4). On brief, the Attorney General discussed some of the alternative adjustments proposed by her witness (Attorney General Brief at 48-50).

removal of post-test year NGSC plant additions, the Attorney General argues that $574,716 in incremental expenses associated with projected OMS operating costs should be removed from the Company's cost of service (Attorney General Brief at 44).

v. SAP Enhancement Release 1 Expenses

Fourth, the Attorney General argues that $2.7 million in costs associated with EHR1 should be removed from the adjusted test year rent cost as a non-recurring item (Attorney General Brief at 48). She argues that the EHR1 represents another step and update in the overall SAP system that was included in the post-test year NGSC IS plant additions, and that while the Company agreed in rebuttal to reduce the $2.7 million expense to $2.3 million through amortization over seven years, the entire $2.7 million should be excluded from cost of service (Attorney General Brief at 49, citing Exh. NG--RRP-Rebuttal-1, at 28).

vi. Return on USFP SAP System Assets

The Attorney General argues that the return on USFP SAP system assets should be reduced because of (1) the extent of the problems the Company experienced with the USFP SAP implementation, (2) the Company's imprudence, and (3) the effect of these implementation problems on the Company's operations, including cost overruns and the need for subsequent system stabilization efforts (Attorney General Brief at 45-47, citing Exhs. NGRRP-9, at 3; AG-DR-1, at 31-32, 33-35; AG-4-4; AG-23-9, Att. 1; Tr. 5, at 586, 607-608; Attorney General Reply Brief at 20). The Attorney General claims that the Company attempts to gloss over the serious USFP SAP problems (Attorney General Brief at 21). She maintains that the Company itself identified the problems in USFP post-implementation review documents that reflect actions that were not reasonable or prudent (Attorney General Reply Brief at 21-22,

citing Exhs. AG-4-6, Att. 66; AG-23-9, Att. 1).[208] Additionally, the Attorney General challenges the inclusion of certain USFP SAP Release 3 ("R3") stabilization costs in the IS rent expense that further drive up costs to ratepayers, and despite the Company's claim that all SAP stabilization costs were charged to the parent (Attorney General Brief at 47).

In light of what the Attorney General considers to be the severity of the implementation problems and imprudence of the root causes, she recommends that the return component be limited to NCSC's 3.70 percent long-term debt rate (Attorney General Brief at 47-48; Attorney General Reply Brief at 20, 22). The Attorney General avers that the combination of the lower 3.70 percent return and limiting the inclusion of NGSC's IS net assets to the test year-end balance as discussed above would further reduce IS rent expense by $2,271,485 (Attorney General Brief at 48).

vii. Rate of Return on IS Assets

The Attorney General challenges the Company's proposed use of a 10.63 percent overall pre-tax return to the NGSC IS assets in determining the rent expense, arguing that the ROE component of the 10.63 percent rate should be revised to the allowed ROE approved by the Department in this case (Attorney General Brief at 43). She states that the Company agreed in its rebuttal that the NGSC rent expense should be based on the ROE approved by the Department (Attorney General Brief at 43, citing Exh. NG-RRP-Rebuttal-1, at 20). Based on her recommended ROE of 7.80 percent, the Attorney General states that the revised return results in

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208 Exhibit AG-23-29, Attachment 1 is a copy of an October 2013 presentation to members of the New York State Public Service Commission as part of the Comprehensive Management and Operations Audit of National Grid USA's New York Gas Companies (Case No. 13-G-0009). Exhibit AG-4-6, Attachment 66 is a confidential report titled "USFP R1 Review: Lessons Learned" that was prepared by a consultant and dated November 29, 2014.

a reduction to the Company's proposed IS rent expense (Attorney General Brief at 43-44, citing Exh. AG-DR-2, Sch. 7, at 1 and 2).[209] Therefore, the Attorney General recommends reducing the equity return applied to NGSC IS assets from the 10.50 percent ROE incorporated in the Company's original filing to the 7.80 percent recommended by the Attorney General in this case (Attorney General Brief at 40; Attorney General Reply Brief at 71).

viii. Imputed EHR1 Savings

The Attorney General argues that if the Department allows the inclusion of post-test year EHR1 system plant additions in the determination of NGSC rent expenses, the Company also should net out the associated cost savings that the enhancements generate (Attorney General Brief at 49; Attorney General Reply Brief at 23). In support of her position, the Attorney General states that the Company had identified potential estimated cost savings associated with the EHR1 projects that would begin accruing by the middle of 2016 (Attorney General Brief at 49; Attorney General Reply Brief at 23). Citing the Company's figure of $6.46 million in potential savings at the service company level and applying an 18.85 percent[210] allocation factor used to determine MECo and Nantucket Electric's combined portion of expenses and adjustments, the Attorney General recommends reducing the IS rent expense by $1,217,710 to incorporate projected costs savings (Attorney General Brief at 49-50, citing Exhs. AG-DR-1,

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209 The Attorney General notes that her calculation of the reduction to IS rent expense using a pre-tax return of 8.96 percent offered on brief does not include any potential additional disallowances or ROE reductions associated with the USFP SAP systems implementation (Attorney General Brief at 44). She addresses these proposed adjustments elsewhere in her brief (Attorney General Brief at 44-48).

210 The 18.85 percent allocation factor represents the combined allocations of 18.58 percent for Massachusetts Electric and 0.27 percent for Nantucket Electric (Exh.WP-NG-RRP-9, at 5-8).

at 48; AG-DR-3, Sch. 4; AG-23-11; Attorney General Reply Brief at 23). Excluding these cost savings, the Attorney General maintains, will further hinder efforts to match revenues, expense, and investments in a revenue requirement equation already distorted by the inclusion of the post-test year rent expense (Attorney General Reply Brief at 23).

b. Company

i. Overview

National Grid maintains that the $38,519,355 in total IS and facilities rental expenses, comprising normalized test year expenses of $28,391,851 and an additional $10,127,504 in post-test year adjustments, are reasonable and prudently incurred, and therefore should be included in the cost of service (Company Brief at 31; Company Reply Brief at 33, citing Exh. NG-RRP-2, at 15 (Rev. 3)). The Company argues that the Attorney General's recommendations to eliminate certain IS rental expenses from cost of service are without merit and should be rejected by the Department (Company Brief at 31).

In support of its IS rental proposals and in opposition to the Attorney General's recommendations, the Company emphasizes that: (1) the post-test year IS adjustments are significant and prudent; (2) there is no basis for a reduced return on USFP; (3) the EHR1 implementation expense should be allowed; and (4) savings should not be imputed (Company Brief at 32-44; Company Reply Brief at 24-33). Noting that the Attorney General did not contest the proposed facilities rental expenses, the Company states that the Department should approve recovery of the facilities rental costs without modification (Company Brief at 31 n.10, 37).

ii. Post-Test Year IS Additions

The Company dismisses the Attorney General's recommendation to remove $9,026,666 in incremental IS rental charges from NGSC, related to post-test year NGSC IS plant additions (Company Brief at 31-32, citing Attorney General Brief at 41-42). The Company also contests the Attorney General's opposition to post-test year plant additions as the basis for normalization adjustments associated with NGSC rate base balances (Company Brief at 32-33).

The Company asserts that the IS projects at issue represent significant NGSC investments (Company Brief at 33-34; Company Reply Brief at 29). In particular, the Company notes that approximately $9.0 million in post-test year rent expense associated with the NGSC IS rental charges is greater than two percent of the Company's total distribution O&M expense portion of its cost of service (Company Brief at 34). The Company argues that the Attorney General obscures the facts of the investment by referring to the Company's allocated portion of the rental fees instead of the actual dollar amounts associated with the NGSC IS investments (Company Brief at 34). According to the Company, the total NGSC investment associated with the IS projects in question is $145,672,554, and represents over 41 percent of the NGSC's total net IS investment of $350,629,068, thereby reinforcing the significance of the amounts both for the Company and for NGSC (Company Brief at 34, citing Tr. 6, at 948, 951-952; Company Reply Brief at 26).[211]

[211] National Grid's witness stated that the Company proposed to recover the post-test year IS rental expenses as operating expenses rather than as a rate base item, which would earn a return for the Company (Tr. 6, at 948, 951). The same witness, however, also stated that the NGSC calculation of the IS rental expense allocated to MECo and Nantucket Electric included a return on capital at the service company level (Tr. 6, at 948-949).

The Company presents alternative interpretations of the significance standard in opposition to the Attorney General's arguments (Company Reply Brief at 25-27). First, the Company disputes the Attorney General's contention that significance should be determined on an individual project basis and not on a collective basis (Company Reply Brief at 25-26). According to the Company, there is no rule or practice set by the Department that precludes consideration of the IS investments as a group (Company Reply Brief at 26). Additionally, the Company avers that the IS projects in question are part of an interrelated series of improvements to information systems necessary to serve customers (Company Reply Brief at 28).

Second, the Company maintains that there is no requirement that a capital investment must be significant in relation to the Company's own rate base and not the amount of rate base or investment held by an affiliated entity, even if the investment is made by the affiliated entity (Company Reply Brief at 26). Nor would such a rule make sense, the Company contends, when the investments will be recorded on the Company's books as expense and not as capital (Company Reply Brief at 26). On a related matter, the Company disagrees with the Attorney General's discounting of IS project cost comparisons to total net investments in IS systems, arguing that the Attorney General overlooks the fact that as a service company, the bulk of NGSC's assets would be IS rather than distribution plant or other booked rate base items (Company Reply Brief at 26). The Company notes that NGSC's total net investment in IS at the end of the test year (i.e., June 30, 2015) represented 36 percent of the service company's total rate base of $862,881,567 (Company Reply Brief at 26, citing NGSC's 2015 FERC Form 60).

Third, the Company takes issue with the Attorney General's claim that MECo and Nantucket Electric's shared 18.85 percent allocated portion of the $145.67 million IS rental

expense disqualifies the significance of the Company's stake in the total (Company Reply Brief at 26-27). Such an argument, the Company maintains, ignores the rationale of a holding company structure, which is to provide benefits to each operating company in relation to shared services, particularly in the area of IS where operating affiliates can obtain access to systems they could not afford on their own (Company Reply Brief at 27). It will always be the case, the Company argues, that the share of costs paid by individual operating companies may not be significant relative to the whole (Company Reply Brief at 27). Therefore, the Company adds, if all the smaller allocated portions of operating company IS rental expenses are deemed to be insignificant, then it is not possible for NGSC to recover its costs (Company Reply Brief at 27).

For these reasons, the Company contends that the Department cannot reasonably rely on a comparison of the allocated share of expense to the whole expense when determining whether the post-test year IS rent charges in the instant case are significant and therefore eligible for cost recovery (Company Reply Brief at 27). Rather, it recommends that the Department consider the comparison provided by the Company as the signal for whether cost recovery is warranted, i.e., a comparison of NGSC's $145.67 million of plant additions to $350,629,068 total net IS investment (Company Reply Brief at 27).

Additionally, the Company argues that excluding the post-test year change in IS rental expense associated with post-test year NGSC IS investments would cause the Company to experience a significant shortfall in its rate recovery, since all of the IS projects requested for inclusion in rates have seven-year amortization periods, which are far shorter than depreciation periods for typical utility plant and amount to nearly $40 million in amortized asset recovery

(Company Brief at 36; Company Reply Brief at 29, citing Exh. NG-RRP-Rebuttal-4, at 5).[212] The Company contends that if the Department accepted the Attorney General's recommendation to deny inclusion of post-test year IS rental expenses, the decision could potentially cause the Company to lose more than half of its IS investment even with a short period between base-rate cases (Company Brief at 36; Company Reply Brief at 29). The decision, according to the Company, would be tantamount to disallowing a substantial portion of the investment without any finding of imprudence, and despite the fact that the investments in question are in service and benefitting customers (Company Brief at 37; Company Reply Brief at 29).

Based on the foregoing analysis, National Grid concludes that the Department should reject the Attorney General's recommendation and instead authorize the inclusion of IS rental expense associated with the post-test year NGSC IS investments (Company Brief at 37). Consistent with this treatment, the Company urges the Department to allow the inclusion of incremental OMS operating expenses in the Company's cost of service (Company Brief at 37).

iii. SAP EHR1 Expenses

In response to the Attorney General's recommendation to remove $2.7 million in EHR1 system expenses as a non-recurring item, the Company argues that the appropriate treatment of this expense is to amortize it, as supported by Department precedent (Company Brief at 42). The Company contends that the Attorney General's recommendation of complete disallowance has no basis insofar as she fails to support any claim that the IS rental expense associated with the

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212 The Company cites to $38,216,613 in projected accumulated amortization, derived from subtracting a balance of $107,455,613 representing the total value of NGSC IS project investments at September 30, 2017 from the forecast total NGSC IS expense of $145,672,554 incurred between June 30, 2015 and May 31, 2016 (Exhs. NG-RRP-Rebuttal-1, at 20; NG-RRP-Rebuttal-4, at 5).

EHR1 system is indeterminate, unreasonable, or imprudent, and that she fails to demonstrate that the seven-year amortization period is inappropriate (Company Brief at 42-43).

National Grid argues that IT expenses, such as the EHR1 expenditures, are amortized over time in a way that strikes a balance between the need to continue improvements in service technology and the need to maintain intergenerational integrity (Company Brief at 42, citing D.P.U. 13-75, at 217; D.T.E. 02-24/25, at 153; Boston Gas Company, D.P.U. 93-60-D at 4 (1994)). Because the EHR1 system is being amortized over seven years, the Company reasons that the related EHR1 implementation expenses should be amortized as well (Company Brief at 42, citing Exhs. NG-RRP-Rebuttal-4, at 1; NG-RRP-2 (REV-2), at 15). Accordingly, the Company recommends that the Department reject the Attorney General's argument and authorize the proposed amortization of EHR1 expense (Company Brief at 43).

iv. Return on USFP SAP Assets

National Grid contests the Attorney General's argument for reducing NGSC's return to the 3.70 percent long-term debt rate based on problems and imprudence associated with the USFP system implementation (Company Brief at 37; Company Reply Brief at 30-32). The Company asserts that the Attorney General's recommended penalty of a reduced return on the USFP system is unwarranted because the implementation issues were caused by factors the Company already explained, factors that did not include the types of unreasonable decisions made during project development that meet the requirements for a finding of imprudence

(Company Brief at 38-39, citing Exh. NG-RRP-Rebuttal-1, at 27; Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983)).[213]

The Company specifically challenges the testimony of the Attorney General's witness, who argued that the Company should have anticipated the problems with the USFP implementation given difficulties with roll outs of SAP systems at other companies (Company Reply Brief at 30-31). The witness, according to the Company, readily admitted no technical or practical experience with SAP implementation (Company Reply Brief at 30, citing Tr. 15, at 1593-1594, 1599; Attorney General Reply Brief at 20). Conversely, the Company asserts that it demonstrated that complex, multi-layered IS investments such as USFP SAP cannot simply be compared to other companies' SAP implementation experiences, whether utilities or not (Company Reply Brief at 31, citing Tr. 5, at 600).[214]

The Company also challenges the Attorney General's reliance on a report to the NYPSC expounding on issues encountered in the USFP SAP implementation and lessons learned as the basis for an imprudence finding on the equity return component of the USFP rental expense (Company Reply Brief at 31-32, citing Attorney General Reply Brief at 22;

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213 The Company notes that a review of the prudence of a company's actions is not dependent on whether budget estimates later proved to be accurate, but rather upon whether the assumptions made were reasonable given the facts known at the time (Company Brief at 39, citing D.P.U. 95-118, at 39-40; D.P.U. 93-60, at 35; D.P.U. 84-145-A at 26).

214 The Company's witness testified that it is difficult to compare large, complex software projects across utilities or across companies in general since the systems, which are generally located at the center of a company's operations and interface with a number of other systems, are designed specifically in recognition of the environment in which they must function (Company Reply Brief at 31, citing Tr. 5, at 600).

Exh. AG-4-6, Att. 66).[215] According to the Company, the Attorney General misses the fact that the report's findings helped propel National Grid USA to write off $552 million in shareholder value associated with the USFP SAP implementation to shield customers from the financial impact of the implementation problems (Company Reply Brief at 32). The Company also notes that the NYPSC determined that the remaining costs were recoverable through customer rates, and, therefore, authorized Niagara Mohawk Power Corporation and Brooklyn Union Gas Company, both National Grid operating companies in New York, to recover the same category of USFP SAP costs included in the instant case (Company Reply Brief at 32, citing Exh. NG-ISP-Rebuttal-1, at 18). The Company avers that if the remaining costs were subject to disallowance on the basis of the report findings, the NYPSC would have come to that conclusion (Company Reply Brief at 32).

Further, the Company contests the Attorney General's claim that R3 stabilization costs were inappropriately included in its proposed revenue requirement (Company Brief at 38). The Company asserts that it included only the portion of R3 investment attributable to system enhancements to add functionality to the SAP system and not to stabilize it (Company Brief at 38).

In sum, the Company argues that the Attorney General provided no justification to meet the imprudence standard, and that National Grid was forthcoming in voluntarily excluding all capital and O&M costs associated with system stabilization made necessary by implementation issues (Company Brief at 39). Further, the Company maintains that the Attorney General's recommended ROE adjustment is not based on any specific cost element or showing that the

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215 See n.208 above.

costs were not actually incurred or are computed incorrectly, or any other substantive basis (Company Brief at 40).[216] Therefore, the Company recommends the Department reject the Attorney General's adjusted ROE (Company Brief at 42).

v. Imputed EHR1 Savings

National Grid opposes the Attorney General's recommendation to impute $1.2 million in projected EHR1 project savings to the Company's revenue requirement (Company Brief at 43). The Company argues that the Attorney General's reliance on potential estimated cost savings ignores record evidence showing no basis for making such an adjustment (Company Brief at 43).[217] National Grid maintains that although it provides some quantitative analysis for prospective savings, this savings estimate was preliminary in nature, because (1) the estimates were made during the conceptual design phase of EHR1; (2) the majority of the quantitative benefits were associated with avoiding costs, the extent of which would not have been known until the actual execution of the projects; and (3) after four years of SAP implementation, stabilization and enhancement work, National Grid ultimately recognized that identifiable benefits were qualitative and not quantitative (Company Brief at 43, citing Exh. AG-23-11; Company Reply Brief at 33). The Company further claims that while the Attorney General acknowledged that potential savings were associated with avoided future costs rather than

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216 The Company explained that the difference between pre-implementation estimates and final costs should not be viewed as the terminus of a one-dimensional systems replacement project, but rather the outcome of a complex, iterative design and planning effort integrating multiple business processes into the final scope of USFP SAP (Company Brief at 40-41, citing Exh. NG-ISP-Rebuttal-1, at 14-15).

217 The Company identified $6.46 million of potential cost savings, as discussed above, in response to an information request from the Attorney General asking for any updated quantifications of savings associated with SAP implementation (Exh. AG-23-11).

reduced existing costs, she chose to ignore the information when making her recommendation (Company Brief at 44, citing, Exh. AG-DR-1, at 47). Moreover, the Company maintains that the Attorney General did not reference any evidence showing either any realized net savings as a result of the EHR1 implementation or demonstrating that net savings are routinely expected from such system enhancements (Company Brief at 44; Company Reply Brief at 33).[218] The Company further asserts that the Attorney General failed to respond to evidence that the benefits of potential savings are qualitative and that achieving estimated savings depends on a multitude of factors that make realization difficult (Company Reply Brief at 33, citing Company Brief at 43; Exh. AG-23-11). Accordingly, the Company contends that the Department should disregard the Attorney General's recommendation to impute $1.2 million in projected EHR1 implementation savings to the revenue request (Company Brief at 44; Company Reply Brief at 33).

4. Analysis and Findings

a. Introduction

The Department first will review the Company's proposal for test year adjustments to rental expenses for leased facilities. The Company proposed adjustments to expenses for facilities in Northborough and Waltham, among other Massachusetts locations, and in New York, Rhode Island, and Washington, D.C. No intervenors commented on facilities lease expenses.

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218 The Company noted a similar recommendation of the Attorney General's in D.P.U. 13-75 when she sought to offset costs of a NiSource financial platform, NIFIT, with purported savings from implementation of the platform (Company Brief at 44). The Company further noted that the Department rejected the Attorney General's recommendation, finding that the benefits of the NIFIT system were not necessarily quantifiable in monetary terms (Company Brief at 44, citing D.P.U. 13-75, at 114).

The Department will then examine evidence supporting National Grid's proposed revenue requests for post-test year IS rent additions. Specifically, the Department will decide whether the Company should: (1) recover costs related to post-test year IS rent adjustments, including the proposed $9,026,666 post-test year plant additions and associated incremental OMS operating expenses; (2) reduce NGSC's return on IS assets in general and on USFP SAP implementation costs in particular; (3) remove $2.7 million in EHR1 implementation costs; and (4) impute $1.2 million in projected savings to the revenue requirement.

In arriving at the findings, the Department will examine the following issues central to the Attorney General's opposition arguments: (1) use of the Company's rate base as the basis for measuring the significance of IS rent charges to MECo and Nantucket Electric; (2) the prudence of the USFP SAP implementation given problems with its roll-out; and (3) characterization of the non-recurring test year EHR1 implementation expense as a stabilization cost.

b. Facilities Lease Expense

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.P.U. 10-55, at 268; D.P.U. 09-39, at 155; D.T.E. 03-40, at 171; Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1989). The standard for inclusion of lease expense is one of reasonableness. D.P.U. 89-114/90-331/91-80 (Phase I) at 96. Known and measurable increases in rental expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service as are operating costs (e.g., maintenance, property taxes) covered by the lessee. D.P.U. 95-118, at 42 n.24; D.P.U. 88-67 (Phase I) at 95-97.

During the test year, National Grid booked lease-related expenses totaling $8,787,277 for facilities, including $3,308,931 for Reservoir Woods, Waltham; $1,462,878 for Northborough;

and $4,015,468 for all other facilities (Exhs. NG-RRP-2 (REV-3), at 15; WP NG-RRP-8).[219] No intervenors commented on the Company's proposed facilities rental expense adjustments. The Department finds that the proposed adjustments to the Company's facilities lease expenses are reasonable and represent a known and measurable change to the Company's test year cost of service (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8; DPU-31-24; AG-1-64; AG-1-92). D.P.U. 10-55, at 260-268; D.P.U. 09-39, at 156-158; D.P.U. 95-118, at 42 n.24; D.P.U. 89-114/90-331/91-80 (Phase I) at 153. Accordingly, the Department accepts National Grid's proposed expense adjustments for its facilities.

c. Post-Test Year IS Additions

As noted above, the Attorney General opposes the Company's inclusion of $9,026,666 in post-test year IS rent expense, stating that these adjustments break with Department precedent requiring the utility to demonstrate that post-test year additions are significant relative to the operating company's test year end rate base. In turn, National Grid maintains that there is no basis for applying the Department's post-test year rate base standard to costs that are treated as expenses on a company's books.

In the instant case, the associated costs are not recorded as plant investment, but instead are recorded as expenses (Exhs. NG-RRP-1, at 12; NG-RRP-Rebuttal-1, at 22; Tr. 6, at 946-952). The Department has found that because lease expenses do not represent a capital improvement to the Company, such expenses should not constitute a rate base item. D.P.U. 09-39, at 155; D.P.U. 95-118, at 41-46; NYNEX Price Cap, D.P.U. 94-50, at 436 (1995);

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219 As noted above in Section VIII.O.2.b, these lease-related expenses reflect normalizing adjustments totaling $1,602,011, representing a decrease to the total test year end amount (Exhs. NG-RRP-2, at 15 (Rev. 3); WP-NG-RRP-8; DPU-31-24).

D.P.U. 84-94, at 18. The Department finds that rental expense is a component of a company's operating and maintenance expense, not a component of its capital structure. NGSC owns the IS assets in question and therefore its rate base applies to those assets. While the lease arrangements provide the Company with benefits from the IT system, they do not give the Company an ownership interest in the assets or permit the Company to include associated capital expenditures in rate base. D.P.U. 09-39, at 155; D.P.U. 85-270, at 186; D.P.U. 84-94, at 18. We also find that these IS rent expenses are known and measurable (Exhs. NG-RRP-2, at 15 (Rev. 3); NG-RRP-4 (Rev. 1); WP NG-RRP-9 at 4, 8, 12 (Rev. 1); AG-DR-1, at 39-40). Accordingly, the Department declines to accept the Attorney General's recommendation to exclude the Company's $9,026,666 in IS rent expense normalization from the adjusted test year expenses. However, as discussed below, the Department will adjust this amount based on NGSC's return on rate base.

Consistent with our disposition of this issue, the Department declines to adopt the Attorney General's recommendation to remove incremental OMS expenses of $574,716. Further, we find that incremental EMS expenses of $526,122 are appropriate for recovery. Therefore, the Department includes these expenses in the Company's cost of service.

d. Reduced NGSC Returns

The Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a formula that is both cost-effective in application and non-discriminatory for those services specifically rendered to the utility by the affiliate and for

general services that may be allocated by the affiliate to all operating affiliates. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 143-146 (2012); D.P.U. 95-118, at 41; Milford Water Company, D.P.U. 92-101, at 43-46 (1992); D.P.U. 89-114/90-331/91-80 (Phase I) at 79-80 (1991); D.P.U. 85-137, at 51-52.

The Attorney General has recommended that the Department reduce the return portion of the IS rent expense on two levels. First, the Attorney General recommends that the return specifically associated with USFP SAP implementation costs be reduced to 3.70 percent, representing NGSC's long-term-debt rate. Second, the Attorney General recommends that the return on all NGSC IS asset-related costs be based on the ROE ultimately allowed by the Department; National Grid concurs with this second recommendation (Exh. NG-RRP-Rebuttal-1, at 20).

Regarding her recommendation to reduce the return on USFP SAP implementation to NGSC's long-term debt rate of 3.70 percent, the Attorney General draws on the extensive record evidence detailing USFP SAP implementation problems and subsequent corrective stabilization efforts to argue that Company denial of unreasonable decision making is an attempt to gloss over her legitimate claims of imprudence. The extent of the problems associated with USFP SAP implementation is acknowledged by the Company and is well-documented in the instant case (Exhs. NG-MLR-1, at 27-28; AG-4-6; AG-16-12; AG-23-9, Att. 1; Tr. 1, at 45-54; Tr. 5, at 598-600, 605-608).[220] NGSC executives explained details of the root causes, which the Attorney General cited as evidence of imprudence behind the decisions underpinning the USFP

[220] In particular, Exhibit AG-4-6 includes 72 attachments, covering USFP SAP implementation audits and update reports on system improvements resulting from NGSC's responses to identified problems and lessons learned (Exhs. AG-4-6; AG-23-9).

SAP development and roll-out (Exhs. AG-23-9, Att. 1; Tr. 1, at 45-54, 56-57; Tr. 5, at 607-608). The Attorney General focuses on increases in total projected costs throughout the project's development to attach a financial consequence to the problems experienced at implementation (Exhs. AG-DR-1, at 33-35; AG-4-4; AG-4-21). The Department, however, disagrees with the Attorney General's suggestion that the implementation problems and cost increases are linked and based on unreasonable and imprudent decisions.

Regarding increases in project costs, a prudence review of a company's actions is not dependent upon whether budget estimates later prove to be accurate, but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. D.P.U. 93-60, at 35; D.P.U. 85-270, at 23-24. Documents recording details of the early project scoping efforts indicate that the Company was aware that only final detailed design phases closer to project implementation would prove the accuracy and validity of preliminary project scoping and cost estimates (Exh. AG-4-4, Atts. 2-5). Overall, the record shows that NGSC embarked on a necessary update of critical but inadequate information systems, employing an organized planning and development process that explored alternative strategies and vendors in an attempt to improve the systems at a competitive and reasonable price (Exhs. WP-NG-RRP-9; AG-2-25; AG-4-1; AG-4-2; AG-4-4 through AG-4-18; AG-11-14; Tr. 5, at 568-580). We note that among those improvements is the OMS, an IS asset developed and implemented in direct response to a Department Order mandating the Company to improve emergency management procedures related to outages and wires-down response and reporting. D.P.U. 11-85-A/D.P.U. 11-119-A at 151-153.

The record also shows that the IS rental expenses charged by NGSC were allocated to the utility by a cost-effective and non-discriminatory formula (Exhs. WP-NG-RRP-9; DPU-31-16; DPU-31-19; DPU-31-20; AG-1-92; AG-11-2; AG-11-3; AG-11-4). The Department acknowledges that the USFP SAP implementation in 2012 suffered from defects in system construction as well as from an initial lack of understanding by those employees running it (Tr. 5, at 607). The record makes abundantly clear that the NGSC strove to correct those defects at no cost to ratepayers through a $552,228,831 stabilization program subsidized by shareholders (Exhs. NG-MLR-1, at 29; AG-4-10; AG-4-13; AG-4-20; AG-15-11; AG-23-1; Tr. 1, at 41-43, 46-48, 50-57; Tr. 5, at 585-586, 598, 608). What is not clear is whether the Company could have avoided similar problems had NGSC chosen a different system vendor and development path (Exhs. NG-AG-1-6; AG-4-15; NG-11; Tr. 11, at 1595-1600, 1686-1687). Because the utility's actions, based on all that it knew or should have known at the time, were reasonable and prudent, and because the parent company absorbed the stabilization costs, we decline to accept the Attorney General's recommendation of reducing the return on USFP SAP expenses to 3.70 percent.

Regarding the Attorney General's second recommendation, the Department has found a ROE of 9.90 percent is appropriate for the Company (see Section XII.E below). On that basis, the Department finds that application of the Company's proposed capital structure, including a proposed ROE of 10.5 percent, to determine the Company's allocated share of the IS investment would result in Massachusetts ratepayers inappropriately subsidizing the operations of NGSC. To guard against Massachusetts ratepayers inappropriately subsidizing the operations of NGSC, the Department will recalculate the return on NGSC assets using NGSC's capital structure and

the 9.90 percent ROE authorized in the instant case. D.P.U. 10-55, at 266-267; D.P.U. 11-43, at 145; D.P.U. 08-27, at 82. Application of the 9.90 percent ROE approved in this order to NGSC's capital structure produces an overall weighted cost of capital of 6.80 percent, and a pretax weighted cost of capital of 10.13 percent (see Exh. NG-RRP-4, at 6 (Rev. 1)). Application of the pretax weighted cost of capital to NGSC's allocation of IT services to the Company yields $19,409,402 in adjusted test year IS rent expense and $8,891,752 in adjusted post-test year IS rent expense (see Exhs. NG-RRP-2, at 15 (Rev. 3)). These amounts when added to the post-test year OMS and EMS operating costs produce a revised IS rent expense of $29,401,991 versus the Company's proposed IS rent expense of $29,732,078 (see Exh. NG-RRP-2, at 15 (Rev. 3); n.201 above). Accordingly, the Department reduces the Company's proposed IS rent expense by $330,087. [221]

e. EHR1 Implementation Costs

The Attorney General's recommendation for eliminating $2.7 million in non-recurring implementation costs associated with EHR1 hinges on an interpretation of this particular project phase as an element of SAP stabilization, for which the associated expenses were charged to the parent company (Exhs. AG-DR-1, at 40-41; AG-4-19; AG-4-20; AG-15-11). Without directly naming the relevant EHR1 project costs as stabilization expenses, the Attorney General nevertheless suggests that they could be construed as such, describing them as SAP systems that were above and beyond NGSC's IS rent expense and with the effect of completing SAP

[221] The $330,087 adjustment consists of (1) a decrease of $195,172 from the Company's proposed adjusted test year amount of $19,604,574 in IS rent, and (2) a decrease of $134,915 from the Company's proposed post-test year amount of $9,026,666 in IS rent (Exh. NG-RRP-2, at 15 (Rev. 3)).

stabilization (Exh. AG-DR-1, at 41).[222] Notably, the expenses involve fees to Deloitte Consulting LLP, the firm that provided much of the stabilization services (Exh. AG-15-11). The Attorney General's challenge to the Company's inclusion of R3-labeled costs booked in the test year exposes a conflict between the Company's claims on stabilization versus non-stabilization costs (Exhs. AG-4-19; AG-4-21; Tr. 5, at 583-592). The Company states that it charged all stabilization costs to the parent company, yet R3 costs that a Company witness clearly identifies as meant for stabilizing the system are included in the revenue request (Exhs. NG-MLR-1, at 29; NG-RRP-2, at 5; WP-NG-RRP-9, at 3, 7; AG-4-19; AG-4-21; Tr. 5, at 585-586). The Company's response that the R3 costs in question included only investments in system enhancements not equivalent to stabilization measures leaves us with a semantics question for which we must look to the record to answer (Exhs. AG-4-10; AG-4-20; AG-23-2).

In the extensive confidential EHR1 project update and review reports submitted to National Grid parent executives, R3 project status reports detail a USFP stabilization phase that ends in September 2014 (Exhs. AG-4-6, Atts. 65 and 72). The Company draws a clear line at September 30, 2014 as the divide separating stabilization and EHR1 implementation projects (Exhs. AG-4-6, Atts. 49, 61 and 65). The post-stabilization USFP EHR1 implementation went live in December 2014 with a second phase rolling out in January 2015, which corroborates with the Company's listing of the various USFP EHR1 components among test year charges challenged by the Attorney General, such as supply chain, finance, IT-delivery, and payroll

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222 In reference to the $2.7 million, the Attorney General witness states, "[H]opefully now that the EHR1 upgrade and enhancements have been implemented, the Company will be past the need to stabilize the USFP SAP systems and these significant SAP implementation expenses will not be an annually recurring event" (Exh. AG-DR-1, at 41).

(Exhs. AG-4-6, Att. 61; AG-4-19). The Company's labeling of these charges as R3 is confusing, even if its witness described them as enhancements (after associating them with stabilization) (Exh. Tr. 5, at 585-591). We accept the Company's documentation of these different project phases and the vendor fees to identify them clearly as post-stabilization enhancements to the EHR1 implementation intended to finish the core SAP system roll-out (Exhs. AG-4-6, Atts. 49, 61, 65 and 72; AG-15-11).[223]

The evidence on the record points to such expenses supporting the core project and not stabilization, with contracts, invoices, and consultant reports describing shortcomings of the Company's base line manual work processes, regulatory reporting, and outdated IT systems requiring large-scale and long-term resolution (Exhs. AG-4-19; AG-15-11; Tr. 5, at 583). The expenses support IS assets fundamental to the routine operation of the Company's business processes related to financial management, regulatory reporting, supply chain, payroll, work order cycles, among other essential functions going forward (Exhs. AG-4-6, Att. 65, 72). The Department views these costs as known and measurable elements of the core project and not among the remedial work the NGSC employed for stabilization. Accordingly, we decline to adopt the Attorney General's recommendation to remove the $2.7 million in EHR1 implementation costs from the cost of service.

f. Savings From EHR1 Implementation

The Attorney General contends that if the Department allows the post-test year EHR1 system plant additions in the determination of NGSC rent expenses, the Company's revenue request should reflect a commensurate savings from IS enhancements designed to improve

223 The Company provides 58 invoices from consultants helping to develop and implement post-stabilization EHR1 projects (Exh. 15-11).

business processes. The Company maintains that it never anticipated quantifying savings, although it prepared estimates in response to the Attorney General's request for them (Exhs. AG-23-10; AG-23-11). The Company has emphasized the qualitative nature of anticipated savings, and maintains there is no evidence showing realized net savings as a result of the EHR1 implementation, or that net savings are routinely expected from such system enhancements (Exhs. AG-2-25; AG-23-11).

The Department has previously rejected proposed adjustments for savings achieved by projects when the record showed that the savings are speculative or there was uncertainty that savings would be achieved in the rate year. D.P.U. 13-75, at 114; D.P.U. 05-27, at 129-131; D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51. While National Grid identified a five-year savings estimate of $74.35 million during the conceptual phase of the project, the Company ultimately determined that savings were difficult to quantify, and that the benefits of the project were more qualitative in nature through the implementation of reliable and stable IT platforms, enhanced controls, additional data transparency and sustainable technical solutions (Exhs. AG-4-4, Att. 3; AG-23-10; AG-23-11). The Company identifies potential and expected savings in confidential reports to parent company executives, attaching specific dollar amounts to individual project areas (Exh. AG-4-6 , Atts. 61 and 65).[224] It is clear that the Company and its affiliate expect some savings from the IS enhancements, but these are not yet calculable to the degree required by our precedent. Therefore, the Attorney General's proposed adjustment does not meet the

[224] For instance, the Company is tracking 16 quantitative benefits to improvements in supply chain management expected to achieve $3 million in savings annually, and has identified $10 million in estimated annual savings or avoided costs across SAP-related projects (Exh. AG-4-6, Att. 61).

Department's known and measurable standard. D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51. Accordingly, the Department will not adopt the Attorney General's recommendation.

g. Conclusion

As noted above, the Company proposes to recover $29,732,078 in IS expenses incurred during the test year and through the end of the rate year, September 30, 2017 (Exh. NG-RRP-2, at 15 (Rev. 3)). Based on our findings above, the Department concludes that the appropriate level of IS expense is $29,401,991. Accordingly, the Department will reduce the Company's proposed cost of service by $330,087.

P. Environmental Response Costs

1. Introduction

During the test year, National Grid booked $9,120,244 in environmental remediation expenses associated with its electric operations and former manufactured gas plant ("MGP") sites operated by its corporate predecessors (Exh. AG-1-59, Att.).[225] The Company funds its environmental remediation activities through its Environmental Hazardous Waste Fund ("Environmental Response Fund") (Exh. AG-1-59). The Environmental Response Fund was created as part of a settlement agreement ("1993 Settlement") in Massachusetts Electric Company, D.P.U. 93-194 (1993), and is intended to provide for National Grid's environmental remediation activities at both its former MGP sites and electric operation sites where remediation

225 Many of National Grid's corporate predecessors operated as combination gas and electric utilities, and the Company retains responsibilities for environmental liabilities arising from the operation of these entities (Exh. DPU-25-3). The Company has been engaged in remediation activities at 31 electric operations sites and 27 former MGP sites (Exh. DPU-25-8, Att. 6, at 5-6).

of pre-1980 contamination was underway (Exhs. DPU-25-8, Att. 6, at 3 n.1; AG-1-59; 1993 Settlement, § B).[226] The Environmental Response Fund was initially financed through a one-time shareholder contribution of $30 million, and the Company is authorized to increase the fund balance through annual ratepayer contributions indexed to the Gross Domestic Product Implicit Price Deflator ("GDPIPD") as of October 1 of each year (Exhs. DPU-25-3; DPU-25-4; AG-1-59; 1993 Settlement, § B.2).[227]

National Grid booked $4,017,471 in contributions to the Environmental Response Fund during the test year (Exh. NG-RRP-2, at 25 (Rev. 3)). The Company proposes to increase its contributions to $4,168,528, based on the application of an anticipated increase in the GDPIPD to 3.76 percent for the period from the midpoint of the test year (i.e., December 31, 2014) to the midpoint of the rate year (i.e., April 1, 2017) (Exhs. NG-RPP-1, at 36-37; NG-RPP-2, at 25 (Rev. 3)).[228] Consequently, the Company proposes to increase its test year cost of service by $151,057 (Exh. NG-RPP-2, 25 (Rev. 3)).

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226 The 1993 Settlement incorporates amendments by the settling parties, and was stamp approved by the Commission on November 30, 1993. Pursuant to 220 C.M.R. § 1.10(3), the Department incorporates by reference in this proceeding the stamp approved version of the 1993 Settlement.

227 The Company draws from the Environmental Response Fund to provide for remediation activities, including property purchases and claims settlements (Exh. DPU-25-8, Att. 6, at 8). Rental income associated with several MGP sites, third party recoveries, and interest income on the Environmental Response Fund are treated as offsets against the fund (Exh. DPU-25-8, Att. 6, at 2; 1993 Settlement, § 2(c)). Legal and consultant fees associated with defending or prosecuting environmental remediation claims or liabilities are not recovered through the Environmental Response Fund, but are charged instead to various O&M expense accounts (Exh. DPU-25-7).

228 National Grid uses the same method to compute its proposed inflation allowance (see Section VIII.Q below).

2. Positions of the Parties

National Grid contends that it has appropriately calculated its proposed Environmental Response Fund adjustment based on the increase in the GDPIPD from the mid-point of the test year to the mid-point of the rate year applied to its test year fund contribution (Company Brief at 93, citing Exhs. NG-RPP-1, at 36; NG-RPP-2, at 25 (Rev. 3)). Consequently, the Company argues that the Department should accept the proposed adjustment without modification (Company Brief at 93). No other party addressed this issue on brief.

3. Analysis and Findings

The ratemaking treatment of National Grid's environmental remediation expenses was approved as part of the 1993 Settlement. The Department's authority to consider and approve distribution rates through agreed settlements derives from statute. See G.L. c. 164, §§ 76, 93, 94. Rates approved under this broad discretionary authority must conform to the requirements of statute, i.e., they must be "just and reasonable" and "in the public interest" in order to warrant Department approval. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 05-85, at 28 (2005). While the Department neither would nor should disturb matters established by an approved settlement, the public interest requirement of Chapter 164 remains paramount. D.T.E. 05-85, at 29. The Department has no authority to impair or ignore its own statutory authority or obligations, whether by adjudication or by settlement-approval. D.T.E. 05-85, at 29; see also D.T.E. 99-47, at 21 n.20.

National Grid's environmental remediation expenditures involve a wide range of activities, and include consulting fees, contractor costs, regulatory expenses, and legal fees

(Exh. DPU-25-8, Att. 6, at 11-70). No issues have been raised regarding the prudence of the Company's environmental remediation expenditures.[229] Based on the Company's activities and the Department's familiarity with site remediation, particularly remediation efforts related to former MGP sites, we are satisfied that the Company's environmental remediation activities have been prudently incurred and are reasonable in amount. D.P.U. 10-70, at 183-184; Manufactured Gas Plants, D.P.U. 89-161, at 6-29 (1990). Therefore, the Department finds that these expenditures are eligible for recovery through the Environmental Response Fund.[230]

Pursuant to the terms of the 1993 Settlement, National Grid is permitted to increase its annual contribution to the Environmental Response Fund on October 1 of each year, using the GDPIPD (Exh. AG-1-59; 1993 Settlement, § B.2(b)). The annual inflation-indexed increases in the Environmental Response Fund contributions take effect in October of each year, with one-twelfth of the annual contribution credited to the fund each month (Exh. DPU-25-5; 1993 Settlement, § B.2(b)). National Grid, however, applied an inflation factor of 3.76 percent representing inflation between December 31, 2014 (the midpoint of the test year) and April 1, 2017 (the midpoint of the rate year) (Exhs. NG-RRP-2, at 23, 25 (Rev. 3); WP-NG-RRP-16, at 1-4). The Company's calculation incorrectly presumes that the monthly accrual to its

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229 The 1993 Settlement specifies that nothing in the settlement preludes any party from raising issues related to the prudency of National Grid's environmental remediation expenditures (1993 Settlement, § B.3).

230 The Department also has examined the history of contributions to and payments from the Environmental Response Fund (Exh. DPU-25-8, Atts. 1-6). Based on our review, we are satisfied that the Environmental Response Fund remains an appropriate vehicle by which to fund National Grid's environmental remediation activities. In reaching this finding, we recognize that at some point in the future the Company's MGP and pre-1980 electric sites will be fully remediated, thus eliminating the need for an Environmental Response Fund, but also acknowledge that that time has not yet arrived.

Environmental Response Fund increases monthly based on inflation. Because the Company's monthly contributions are determined in October of each year and remain unchanged until the following October, the next inflation-related adjustment to the monthly contribution would not occur until October of 2017, about a year after the issuance of this Order. This error is partially offset by the Company's use of an unadjusted test year contribution that does not fully account for the increased contribution that became effective on October 1, 2014. Based on these considerations, the Department finds that National Grid has incorrectly calculated its Environmental Response Fund contribution.

The Department will calculate a revised contribution based on the most recent inflation rates provided in the record (RR-DPU-10, Att.).[231] The Department finds that a calculation using inflation rates from the midpoint of the period prior to the October 2015 inflation adjustment (i.e., April 30, 2014) and the date of this Order reliably accounts for the inflation-indexed contributions to the Environmental Response Fund that have occurred since the end of the test year. Based on inflation-related data provided in the record, the inflation factor from the midpoint of the test year to the date of this Order is 3.32 percent (see RR-DPU-10, Att. at 3).[232] The Department finds that an inflation factor of 3.32 percent is an appropriate proxy for the annual inflation-indexed adjustments to the Company's contributions to the Environmental Response Fund permitted by the 1993 Settlement.

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231 These rates are current through April 4, 2016 (RR-DPU-10, Att. at 1).

232 The 3.32 percent inflation allowance represents the difference between an interpolated inflation index of 108.23 as of April 30, 2014 and an interpolated inflation index of 111.55 as of September 30, 2016 (see RR-DPU-10, at 2).

Application of an inflation factor of 3.32 percent to the Company's test year end Environmental Remediation Fund balance of $4,017,471 produces an adjusted balance of $4,150,851, representing an increase of $133,380. National Grid has proposed an increase of $151,057. Therefore, the Department reduces the Company's proposed cost of service by $17,677.

Q. Inflation Allowance

1. Introduction

In its initial filing, National Grid proposed an inflation adjustment of $6,311,460 (Exhs. NG-RRP-1, at 35; NG-RRP-2, at 23). The Company then revised its inflation adjustment to $5,312,904 to account for updated expense reporting (Exh. NG-RRP-2, at 23 (Rev. 3)). The Company calculated its inflation allowance using the GDP-PI or "GDP Deflator" as sourced from the U.S. Bureau of Economic Analysis and Moody's Analytics (Exhs. NG-RRP-2, at 23 (Rev. 3); WP-NG-RRP-16 (Rev. 3)). In its initial filing, National Grid calculated the projected change in the GDP-PI from the midpoint of the test year to the midpoint of the rate year as 4.39 percent (Exh. NG-RRP-2, at 23). During the proceedings, the GDP-PI was updated, and the Company revised the inflation factor to 3.76 percent (Exhs. NG-RRP-2, at 23 (Rev. 3); DPU-25-10).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's inflation adjustment should be calculated by applying an inflation factor of 3.76 percent and not 4.39 percent, which was originally proposed at the time of the Company's filing (Attorney General Brief at 27-28).

According to the Attorney General, the lower inflation factor reflects the most recently available GDP-PI information (Attorney General Brief at 27, citing Exh. AG-DJE-1, at 11).

b. Company

National Grid acknowledges the Attorney General's recommendation to apply the most up-to-date inflation factor of 3.76 percent to the residual test year O&M expense, and the Company notes that it has updated its proposed inflation adjustment accordingly (Company Brief at 73-74). However, the Company contends that if it is appropriate to update the revenue requirement to capture changes in the inflation rate with the goal of achieving rates that are representative of actual costs going forward, then it also should be appropriate to capture post-test year changes in the cost of service that are even more significant, such as changes to the Company's IS rent expense (Company Brief at 74).

3. Analysis and Findings

The inflation allowance recognizes that known and inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113; D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21; Commonwealth Electric Company, D.P.U. 956, at 40 (1982). The Department permits utilities to increase their test year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. In order for the Department to allow a utility to recover an

inflation adjustment, the utility must demonstrate that it has implemented cost-containment measures. D.P.U. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71-72.

National Grid calculated its inflation allowance from the midpoint of the test year to the midpoint of the rate year, using GDP-PI information as an inflation measure (Exhs. NG-RRP-2, at 23 (Rev. 3); WP-NG-RRP-16; DPU-25-10). We find this method to be consistent with Department precedent. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. However, we do not accept the Company's proposed inflation factor of 3.76 percent. Instead, the Department concludes that an inflation adjustment of 3.18 percent based on the most recent forecast of GDP-PI from the midpoint of the test year to the midpoint of the rate year, applied to the Company's approved level of residual O&M expense less the Department's adjustments, is proper in this case (RR-DPU-10, Att. at 3).

With respect to cost containment, National Grid provides that the residual O&M expenses subject to inflation include, but are not limited to, items such as transportation, contractors/consultants, employee expenses and materials (Exh. DPU-1-23, at 1). The majority of these categories of O&M expenses are subject to a competitive procurement process (Exh. DPU-23-1, at 1). For example, the Company utilizes a competitive procurement process in procuring contractors and outside services and has adopted a vigorous RFP process for goods and services to ensure that it obtains the best prices available (Exh. DPU-1-23, at 1). Further, the Company has developed unit pricing for its distribution and civil construction services in order to

minimize costs (Exh. DPU-1-23, at 2).[233] In addition, transmission line, substation, and larger distribution jobs are competitively bid, with each project undergoing the formal procurement process with proposals and pricing stringently chosen and evaluated (Exh. DPU-1-23, at 2). Finally, the Company has instituted a competitive process for vegetation management contractors, allowing long-term contractors to maintain their existing work on the condition that pricing remains within the pre-determined range (Exh. DPU-23-1, at 2).[234] Based on these considerations, the Department finds that the Company has demonstrated and implemented cost control measures that provide direct ratepayer benefits to warrant the allowance of an inflation adjustment.[235]

If an O&M expense has been adjusted or disallowed for ratemaking purposes, such that the adjusted expense is representative of costs to be incurred in the year following new rates, the test year expense is also removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322-323; D.T.E. 05-27, at 204-205; D.T.E. 02-24/25, at 184-185; Blackstone Gas Company, D.T.E. 01-50, at 19 (2001); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). National Grid has removed test year expenses associated with

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233 Unit prices are established through a complex process of negotiations and are intended to be inclusive of all aspects of the scope of work, such as labor, equipment, fuel, administration, safety, environmental compliance, permitting, travel and delays in order to reduce National Grid's exposure to additional charges (Exh. DPU-1-23, at 2).

234 National Grid notes that other contractors are allowed to maintain 90 percent of their previous year share of work if the Company determines that they have maintained a competitive price and a satisfactory safety and performance record (Exh. DPU-1-23, at 2). National Grid reserves ten percent of work for new vendors with the objective of maintaining a competitive platform (Exh. DPU-1-23, at 2).

235 The Company also provided examples of cost containment measures in other areas, such as with medical and dental expenses (see Section VIII.C above).

various O&M expense items that have either been separately adjusted for ratemaking purposes or are not subject to inflationary pressures, such as salaries and wages, medical and dental expense, and group insurance expense (Exhs. NG-RRP-2, at 23 (Rev. 3); DPU-1-23, at 1). The test year expense associated with these items, totaling $210,633,751, has been removed from National Grid's residual O&M expense calculation (Exh. NG-RRP-2, at 23 (Rev. 3)). In addition, the Department has excluded from the residual O&M expense the test year costs associated with the Company's postage expense. Therefore, the test year expenses associated with this item, totaling $6,595,462 will be removed from National Grid's residual O&M expense calculations, as shown in Table 1.

The Company proposes an inflation adjustment of $5,312,904 (Exh. NG-RRP-2 (Rev-3), at 23). As shown in Table 1, the inflation adjustment for National Grid including Department adjustments, and based on an inflation factor of 3.18 percent, is $4,283,625. Accordingly, the Department will reduce the Company's proposed cost of service by $1,029,279.

Table 1:

Test Year O&M Expense Per Books:		$351,934,387
Less Normalizing Adjustments:		
Salaries & Wages:		
MECO / Nantucket Employees		$64,876,622
Service Company Employees		$73,393,666
Affiliated Company Employees		$3,774,236
Medical and Dental Expense		$18,946,518
Group Insurance Expense		$1,466,588
Employee Thrift Plan - Company Match		$4,792,161
FAS112-ASC712		$78,733
Information Services & Facilities Rent Expense		$28,391,851
Uninsured Claims		$4,082,826
Insurance Premiums		$5,909,663
Regulatory Assessments		$4,920,887
Total for Items Specifically Adjusted or not Eligible for Inflation		$210,633,751
Residual O&M Expenses Subject to Inflation per Company:		$141,300,636
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:		3.76%
Inflation Allowance per Company:		$5,312,904
LESS: Department Adjustments		
Company Adjustments	$210,633,751	
Postage Expense	$6,595,462	
Department Sub-total	$217,229,213	
Residual O&M Expense Subject to Inflation:	$134,705,174	
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	3.18%	
Inflation Allowance per DPU:	$4,283,625	
Reduction to Cost of Service:	$1,029,279	

IX. PROPERTY TAX RECOVERY MECHANISM

A. Introduction

On December 16, 2009, the Massachusetts Appellate Tax Board ("Appellate Tax Board") issued a ruling approving the City of Boston Board of Assessors' change in valuation method for assessing utility property. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (December 16, 2009)). Pursuant to that ruling, the Appellate Tax Board approved Boston's change in method from assessing utility property based on net book value (i.e., original cost less depreciation) to assessing utility property based on weighing net book value equally with "reproduction cost new less depreciation" ("RCNLD").[236] Boston Gas Company appealed the ruling to the Supreme Judicial Court ("SJC"), which upheld the Appellate Tax Board's decision and determined that the valuation method used by Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The SJC then remanded the matter to the Appellate Tax Board for further findings. On April 21, 2011, the Appellate Tax Board issued a final ruling in the matter denying Boston Gas Company's appeal of the property tax valuation of the City of Boston Board of Assessors. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (April 21, 2011).

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236 "Reproduction cost new less depreciation" applies a cost-inflationary factor to age the property in question, with a 20 percent floor on the value of the asset. See Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

The Company states that nine municipalities in its service territory have adopted the RCNLD method (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2; Tr. 6, at 896).[237] According to the Company, property tax increases attributable to the RCNLD method in these nine communities amount to $6,304,272 annually (Exhs. NG-RRP-1, at 90; NG-RRP-7).[238] The Company has appealed the use of RCNLD method to the Appellate Tax Board, and it has sought abatements related to the assessments levied by six of the nine municipalities (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2-4; Tr. 6, at 896).[239] The appeals and abatement requests still are pending (Exh. DPU-22-5, at 2-4). National Grid states that if the appeals are denied and all 235 municipalities in its service territory adopt the RCNLD method, the Company would experience an additional annual increase in property tax expense of $28.3 million (Exhs. NG-RRP-1, at 91; NG-RRP-7, at 2).[240]

B. Company Proposal

The Company proposes a Property Tax Provision ("PTP") tariff to address the aforementioned pending abatements and the potential impact of additional communities adopting

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237 These municipalities are: Billerica, Boston, Everett, Lynn, Somerset, Warwick, Westborough, Westminster, and Worcester (Exh. DPU-22-5, at 2).

238 The Company states that it has not withheld payment of any of the incremental property taxes assessed by any of the nine municipalities (Exh. DPU-22-6).

239 The Company has filed appeals and sought abatements relative to the RCNLD method adopted by the following six communities: Billerica, Everett, Lynn, Somerset, Westborough, and Worcester (Exh. DPU-22-5, at 2-4). National Grid states that the incremental taxes assessed by the City of Boston and the Town of Warwick were nominal and not worth the cost of pursuing (RR-DPU-23). Further, National Grid notes that the Town of Westminster accepted the Company's net book value for the 2015-2016 tax year, so there is no tax dispute (RR-DPU-23).

240 National Grid states that if its pending appeals are denied by the Appellate Tax Board, the Company will pursue relief in court (Exh. DPU-22-10).

the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Specifically, the PTP is designed to refund to customers any abatements received by the Company from municipalities as a result of the Company's challenges to the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199 (proposed M.D.P.U. No. 1282)). Pursuant to the PTP, the Company would allocate the net credit from the abatement to rate classes by applying a rate base allocator derived from the Company's most recent general rate case to determine the amount of the credit allocable to each rate class (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Further, the PTP would permit the Company to recover from customers costs incurred in pursuing the abatements and appeals (Exhs. NG-RRP-1, at 92; NG-PP-23, at 199 (proposed M.D.P.U. No. 1282); DPU-22-7, at 2; DPU-33-9; Tr. 6, at 899-902).[241]

The PTP also would permit the Company to measure and recover any increases in annual property tax expense should additional municipalities adopt the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). The Company proposes to calculate the incremental difference in taxes assessed and to accrue that amount until the end of the calendar year preceding a July 1 filing (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Interest would accrue monthly on unrecovered balances at the customer deposit rate (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). National Grid proposes that on July 1 of each year, the Company would make a filing with the Department to

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241 The Company reported legal fees and other costs (e.g., filing fees, independent valuation expert or appraisal fees) associated with the pending appeals of $68,546 (Exhs. DPU-22-5, at 4; DPU-31-9, Atts.). The Company states that if it is unsuccessful in challenging the RCNLD valuation method, it would not seek to recover through the PTP costs related to requests for appeals or abatements (Exhs. DPU-22-8; DPU-31-10). Rather, the Company notes that such costs, to the extent that they are incurred during a test year of a general rate case, would be recovered through base distribution rates resulting from that general rate case (Exh. DPU-31-10).

collect from each rate class the incremental tax and associated carrying costs through a property tax factor ("factor") (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). For each rate class, the factor used to recover the incremental costs would be based on the same rate base allocator used to credit any abatements (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Further, net abatements, if any, would be used to offset the incremental property taxes (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). Pursuant to the Company's proposal, the factor would be effective on the following November 1, for a period of twelve months (Exh. NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). The Company's proposed PTP does not have a specific expiration date (Exh. DPU-22-7, at 3).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Company's proposed PTP should be rejected because it: (1) is speculative in nature; and (2) does not satisfy the Department's long-standing requirements for establishing a new reconciling mechanism (Attorney General Brief at 100; Attorney General Reply Brief at 59). Regarding the first argument, the Attorney General contends that there is no evidence that any other municipality has a pending proposal to adopt the RCNLD (Attorney General Brief at 101; Attorney General Reply Brief at 59). Further, she claims that it is unknown whether the RCNLD method will actually result in an increase in property taxes, that the RCNLD method produced only nominal property tax differences in some communities, and that one municipality reverted back to the net book value method after using the RCNLD method (Attorney General Brief at 101 citing RR-DPU-23; Attorney General Reply Brief at 59). The Attorney General also points out that the Department previously rejected a

similar proposal because it was deemed speculative, and she recommends that the Department do the same in this case (Attorney General Brief at 100-101, citing D.P.U. 12-25).

The Attorney General also argues that the Company has failed to show that the proposed PTP meets the requirements of a new reconciling mechanism (Attorney General Brief at 101 citing NSTAR Gas Company Pension, D.T.E. 03-47-A at 17-18 (2003); Worcester Gas Light Company, D.P.U. 11209, at 8-10 (1946)). In particular, the Attorney General argues, while the property tax amounts may be out of the Company's control, National Grid failed to demonstrate that the RCNLD method results in a significant increase in property taxes relative to the annual expense and its earnings (Attorney General Brief at 101, citing RR-DPU-23; Attorney General Reply Brief at 59).

2. PowerOptions

PowerOptions argues that the Company's proposed property tax recovery mechanism should be rejected (PowerOptions Reply Brief at 3, 12). According to PowerOptions, the proposed PTP is "speculative, theoretical and nonconcrete," and such a prospective charge is not just and reasonable or in the best interest of ratepayers (PowerOptions Reply Brief at 12).

3. Company

According to National Grid, its proposal seeks to treat the recovery of any incremental amount of property tax attributable to the RCNLD method as an "exogenous" event, where recovery would be allowed only where the cost is actually incurred (Company Brief at 194; Company Reply Brief at 78). Thus, the Company contends that there is no speculation involved because "[i]f there is no cost, there is no recovery" (Company Brief at 194). Further, the Company maintains that when a municipality adopts the RCNLD valuation method, experience

has shown that the increase in property taxes is substantial (Company Brief at 194-195 citing Exh. DPU-22-5; Company Reply Brief at 78). In this regard, although National Grid disagrees with the Attorney General's characterization of the proposal as a new reconciling mechanism, the Company asserts that the PTP is warranted because incremental expenses are beyond the Company's control and significant in amount (Company Brief at 195; Company Reply Brief at 78-79).

D. Analysis and Findings

National Grid seeks a new tariff provision that is designed primarily for the potential impact of additional communities adopting the RCNLD method (Exhs. NG-RRP-1, at 91; NG-PP-23, at 199-200 (proposed M.D.P.U. No. 1282)). National Grid's proposal is based, in large part, on its concern that other municipalities will adopt the RCNLD method if it is upheld on appeal, which the Company claims will result in a significant annual increase in property tax expense (Exhs. NG-RRP-1, at 90-91; NG-RRP-7). The Company seeks to treat the recovery of any incremental property tax as an exogenous event, while the Attorney General claims that the proposal is akin to a request for a new reconciling mechanism (Company Brief at 194; Company Reply Brief at 78; Attorney General Brief at 101; Attorney General Reply Brief at 59). We need not reach the merits of either argument.

We find that the Company's proposal is premature, speculative, and rests on such a high degree of uncertainty that it fails to warrant establishment of a new, separate charge. See D.P.U. 12-25, at 333. At the close of the record in this case, only nine of the total 235 communities in National Grid's service territory had adopted the RCNLD method (Exhs. NG-RRP-1, at 90; DPU-22-5, at 2; Tr. 6, at 896). Further, the Company considered that

the incremental tax increase in two of these communities was so immaterial that it chose not choose to pursue abatements or appeals of the respective municipality's decision to adopt the method (RR-DPU-23). In addition, one municipality that had announced adoption of the RCNLD method used the net book value method for the 2015-2016 tax year, rather than the RCNLD method (RR-DPU-23). Moreover, there is no evidence that any other municipality in the Company's service territory had a pending proposal to adopt the RCNLD.

Additionally, uncertainty exists in the appeals process. At the close of the record, the Company's appeals still were pending (see Exh. DPU-22-5, at 3; Tr. 6, at 897).[242] Further, the Company concedes that if the appeals are denied, it will continue to challenge the RCNLD method in court (Exh. DPU-22-10). Therefore, any final decision on the Company's appeals may be years away.

Based on these considerations, the Department is not persuaded that there is a reasonable certainty that a significant number or, in fact, any additional municipalities will adopt the RCNLD method in the near future.[243] Therefore, we find that the proposed PTP is not warranted

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242 Similarly, the record does not disclose any timeline for resolution to the Company's pending abatement requests (see Exh. DPU-22-5, at 3-4).

243 Further, we note that while net book value is a reliable and traditional method for calculating property taxes, we have found that the RCNLD method requires far more intricate calculations and that many smaller municipalities may not have the resources or expertise to easily calculate the new values. D.P.U. 12-25, at 332 n.194. For example, reproduction cost new less depreciation depends on an understanding of current material and labor costs, which can vary widely from region to region. D.P.U. 12-25, at 332 n.194. Smaller municipalities may be forced to hire outside consultants whose fees may exceed the additional tax revenue that a municipality is able to collect through any valuation change. D.P.U. 12-25, at 332 n.194.

at this time.[244] Accordingly, we deny the Company's proposal.[245] Further, we note that in determining the Company's property tax expense (see Section VII.G above), the Department accepted property tax bills from those municipalities that used the RCNLD method of assessment (see Exh. DPU-22-4 & Atts.). Therefore, the higher tax expense for these municipalities is reflected in the Company's representative level of property tax expense.

E. Conclusion

Based on the foregoing, the Department denies the Company's proposal to implement a new tariff to address the pending RCNLD-related abatements and the potential impact of additional communities' adopting the RCNLD method. In its compliance filing, the Company shall revise its tariffs accordingly.

X. ENHANCED VEGETATION MANAGEMENT PILOT

A. Introduction

National Grid's vegetation management program consists of two primary activities – cycle pruning and enhanced hazard tree mitigation ("EHTM") (Exh. DPU-35-1, at 1). Currently, all of the Company's circuits are on a five-year trimming cycle, designed to prune every circuit once every five years (Exh. DPU-35-1, at 1-2). The Company's pruning specifications, which are used by all National Grid contractors, provide for certain minimum distances between all

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244 As provided in Section VIII.G.3 above, the Department will consider, in future base rate proceedings, alternative ratemaking proposals to address property tax changes between base rate cases.

245 To the extent that additional municipalities adopt the RCNLD method and incremental property tax increases to a level that National Grid believes is significant, the Company may petition the Department for appropriate rate making treatment, including a deferral of cost recovery. See, e.g., North Attleboro Gas Company, D.P.U. 93-229 (1994).

vegetation and power lines (Exh. DPU-35-1, at 2).[246] The Company's cycle pruning program is designed to maintain an acceptable clearance between overhead conductors and vegetation to minimize the risk to the public and utility workforce (Exh. DPU-35-1, at 2). Further, the Company notes that it is best-practice to maintain a stable and consistently funded circuit pruning program because it minimizes the risk of public and worker electrocution as well as wild fire events (Exh. DPU-35-1, at 2). In addition, the Company states that consistent cycle pruning also helps maintain service reliability, avoiding potential interruptions from phase-to-phase tree contact (Exh. DPU-35-1, at 2).

National Grid's EHTM program has been in place since 2008 and seeks to identify hazard trees that are diseased, dying, or dead along the Company's circuits and that are susceptible to falling onto power lines and causing power outages and public safety hazards (Tr. 8, at 1308, 1310). The Company states that the ETHM focuses on improving reliability on selected circuits (Exh. DPU-35-1, at 2). National Grid selects circuits for improved reliability based on three-year reliability performance, miles of three-phase bare overhead wire that are most susceptible to tree-related interruptions, tree stocking density, and customer count on the circuit (Exh. DPU-35-1, at 2). The Company reports that over the last three years, it has experienced an average reduction in non-storm customer interruptions of 48 percent on circuits receiving EHTM work when compared to the three-year average prior to the implementation of the EHTM (Exh. DPU-35-1, at 2; Tr. 8, at 1309).

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[246] Specifically, the minimum trimming clearance distances are: (1) ten feet below the wire; (2) six feet to the side; and (3) ten feet above the wire in maintained yard areas, or 15 feet above the wire in unmaintained properties (Exh. DPU-35-1, at 2). These clearance distances were established using expected growth rates for vegetation during the five-year cycle (Exh. DPU-35-1, at 2).

B. Analysis and Findings

Neither the Company nor any intervenors made any proposals regarding the Company's vegetation management program. The Department supports preventative actions undertaken by the Company that seek to improve resiliency, reduce storm restoration costs, preserve critical municipal infrastructure during emergency events, and increase circuit reliability during blue sky days and storm events. In this regard, we acknowledge the Company's efforts to improve reliability and safety on its circuits through its cycle pruning program and EHTM (see Exhs. DPU-35-1, at 2; AG-6-2; AG-6-3).[247] We expect that these efforts will continue to produce appreciable results in the context of reducing customer interruptions outside of storm events.

However, the Department has recognized that a more aggressive storm resiliency program may represent a worthwhile step towards strengthening the Company's distribution system, thus mitigating a portion of the physical damage and financial impacts of future storm events, and thereby benefiting ratepayers. D.P.U. 13-90, at 19. As such, the Department will consider the implementation of a pilot program for National Grid with the goal of further reducing tree-related incidents, customer interruptions, and impact on municipalities along worst performing circuits caused by major weather events.[248]

The Department expects that the pilot program would take place over an established period of time (e.g., five years), and would be designed to target trees that are outside of the

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247 With respect to cycle pruning, we note that the Company is considering moving from a five-year cycle to a four-year cycle, thereby further improving reliability and safety (Tr. 8, at 1313).

248 The Department recently approved a storm resiliency pilot program for Fitchburg Gas and Electric Light Company. See D.P.U. 13-90, at 15-23.

scope of the Company's current vegetation management program. In particular, the scope of work would include extensive hazard tree inspections and removals and the clearing of all overhead and under hanging branches (i.e., ground-to-sky clearing) associated with the worst performing three-phase circuits, based upon a consideration of: (1) tree-related field conditions; (2) customer count; (3) miles of each circuit; and (4) presence of scenic roads or other vegetation management restrictions. The scope of work also would take into account critical infrastructure needs for affected cities and towns, and the locations of critical facilities such as police and fire departments, schools, emergency shelters, other critical business centers, and critical electric company infrastructure.

Based on these considerations, the Department directs National Grid to submit, no later than six months from the date of this Order, a filing for Department review that proposes a specific course of action with respect to implementing the above-described pilot program. In addition to providing specific information regarding the timeframe of the program and the scope of work, the Company also shall identify the anticipated costs necessary to implement the pilot program, as well as any recommended cost recovery mechanism. As part of our review of the filing, the Department may seek additional information from the Company.

XI. RECOVERY OF BASIC SERVICE COSTS

A. Introduction

The Company currently recovers, through its basic service rates, supply-related bad debt, as well as certain administrative costs incurred by the Company in arranging basic service that were transferred from base distribution rates to basic service (M.D.P.U. No. 1262;

Exh. NG-PP-23, at 168 (proposed M.D.P.U. No. 1276)). D.P.U. 09-39, at 314.[249] These costs are recovered from customers through a Basic Service Administrative Cost Factor set forth in the Basic Service Adjustment Provision ("BSAP") that is added to the basic service rate for billing purposes (M.D.P.U. No. 1262; Exh. NG-PP-23, at 168 (proposed M.D.P.U. No. 1276)).

National Grid proposes to recover $24,146,875 in test year basic service-related costs through the BSAP (Exh. NG-PP-17, at 1). These costs are segregated into three categories: (1) wholesale costs, which include electric procurement, procurement support, and letter of credit; (2) direct retail costs, which include customer communication, rate change processing, environmental disclosure label, and bad debt expense; and (3) cash working capital (Exh. NG-PP-17, at 2). The costs associated with the letter of credit, bad debt, and cash working capital comprise approximately $23.6 million of the total costs proposed for recovery through the BSAP (Exh. NG-PP-17, at 2). The remaining costs (approximately $580,000) are attributable to administering basic service (Exhs. NG-PP-17, at 2; NG-PP-Rebuttal at 60).[250]

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249 Basic service (formerly referred to as "default service") is electric generation service that is provided by a distribution company to a customer who chooses not to obtain or is unable to obtain electricity from a supplier, or whose supplier fails to provide generation service. The Department changed the name from default service to basic service in Procurement of Default Service Power Supply for Residential and Small Commercial and Industrial Customers, D.T.E. 04-115-A (2005) and adopted that term in Order Adopting Regulations, D.P.U. 07-105 (2008); see also, G.L. c. 164, § 1.

250 In addition to some of the activities identified above, administering basic service also includes activities such as: (1) coordinating and conducting the competitive solicitation; (2) reviewing and selecting bids; (3) negotiating purchase power agreements; (4) calculating and filing rates; and (5) general monitoring of the program along with the costs associated with the procurement and the related retail costs (Exhs. NG-PP-17, at 2; NG-PP-Rebuttal at 60).

B. Positions of the Parties

1. Direct Energy

According to Direct Energy, the proper allocation of costs to basic service is a fundamental issue for electric suppliers that compete against other suppliers and the Company (Direct Energy Brief at 1). Thus, Direct Energy contends that electric suppliers will not be able to compete fully and fairly with basic service until all costs are properly allocated, so that customers served by a competitive supplier are not forced to pay those costs twice (i.e., once in the rate they pay to their supplier and again in the distribution rates that are recovered by the Company as basic service related costs) (Direct Energy Brief at 1). Direct Energy raises several issues with respect to the Company's assignment of costs to the BSAP.

First, Direct Energy argues that the amount of costs assigned to the BSAP for some cost categories is significantly understated (Direct Energy Brief at 7). In particular, Direct Energy argues that of the $24.1 million in costs that National Grid proposes to recover through the BSAP, only $308,000 of direct labor costs are included in the BSAP (Direct Energy Brief at 6-8). Direct Energy asserts that this amount is too small for the size of the Company (Direct Energy Brief at 8-9). In particular, Direct Energy contends that the Company's assignment to the BSAP of costs associated with the legal and regulatory groups fails to reflect the time and effort expended by these individuals on basic service dockets (Direct Energy Brief at 14). As such, Direct Energy asserts that the Company should allocate at least ten percent of all legal and regulatory costs to the BSAP (Direct Energy Brief at 14 & n.5). Similarly, Direct Energy argues that the Company fails to assign to the BSAP a reasonable amount of personnel costs (Direct

Energy Brief at 13-14). In this regard, Direct Energy asserts that at least 2.5 percent of executive costs should be allocated to BSAP (Direct Energy Brief at 14).

Second, Direct Energy argues that additional cost components should be subject to recovery through the BSAP (Direct Energy Brief at 12). In particular, Direct Energy contends that in addition to the costs that National Grid includes for recovery through the BSAP, the Company also should include all direct and indirect wholesale power procurement costs, as opposed to only a portion of these costs; billing system and related costs (e.g., metering) costs; and customer care costs (Direct Energy Brief at 12-14). More specifically, Direct Energy asserts that the Company should allocate to the BCAP at least 57 percent of billing system and related costs, and at least ten percent of customer care costs (Direct Energy Brief at 12-14, citing Exhs. DE-FL-1, at 20-21; NG-RRP-2).

Next, Direct Energy argues that the Company failed to use an appropriate allocated cost of service study, or to properly follow internal cost allocation procedures, in determining the allocation of BSAP costs (Direct Energy Brief at 9-10). According to Direct Energy, the cost allocation study employed in this proceeding failed to allocate a significant amount of properly allocable costs to the BSAP (Direct Energy Brief at 10). Further, Direct Energy asserts that evidence provided by the Company in response to several record requests demonstrates that the Company is inappropriately assigning costs to the BSAP (Direct Energy Brief at 17-21, citing RR-DPU-30; RR-DPU-34; RR-DPU-35).

Further, Direct Energy contends that the Company's assignment of costs to the BSAP is inconsistent with the Department's Standards of Conduct (Direct Energy Brief at 10-12, citing 220 C.M.R. §§ 12.02, 12.03(17)). In this regard, Direct Energy contends that the

Company's basic service business is a competitive energy affiliate of the distribution company (Direct Energy Brief at 10, citing 220 C.M.R. § 12.02). Thus, according to Direct Energy, the Company must fully and accurately assign costs to the basic service business because that business is functionally separate from the distribution business (Direct Energy Brief at 10). Direct Energy argues that the Company has failed to do so and, consequently, the BSAP is under-charged and "heavily subsidized" by distribution operations (Direct Energy Brief at 12). As such, Direct Energy asserts that basic service is not only provided on a competitive basis, it is unfairly competing with other suppliers in the retail market by offering a product that is priced below its true cost (Direct Energy Brief at 12).

Given these purported allocation deficiencies, Direct Energy argues that the Department should require National Grid to provide a "revamped" allocated cost of service study that reasonably allocates to both distribution and basic service the aforementioned costs, as well as any other costs identified by the Company that relate to the provision of both services (Direct Energy Brief at 15). Further, Direct Energy recommends that a revised BSAP charge should be included in the basic service rate and a corresponding amount returned to all distribution customers as a credit to their distribution rates (Direct Energy Brief at 15). Direct Energy asserts that the charge should be reviewed periodically and adjusted as needed, and that such reconciliation would not be disruptive to customers because, in particular, any changes would apply to only a small portion of the bill (Direct Energy Brief at 15-16).

Finally, Direct Energy argues that its proposed BSAP should be implemented in this case and, in addition, the Department should commence a statewide proceeding in order to implement this approach for the remaining electric distribution companies in Massachusetts (Direct Energy

Brief at 15, 24; Direct Energy Reply Brief at 3-4). In this regard, Direct Energy asserts that a state-wide proceeding should only commence after the Department directs National Grid to move forward with a full unbundling of costs (Direct Energy Brief at 24).[251]

2. Company

The Company argues that pursuant to Department precedent, the only costs that should be included in basic service rates are: (1) wholesale-related costs (i.e., the cost of the generation supply, plus ongoing direct procurement-related costs incurred to competitively purchase the supply); and (2) direct retail costs (i.e., commodity-related bad debt, cash working capital, and certain regulatory costs) (Company Brief at 204, citing Provision of Default Service, D.T.E. 02-40-B at 15-18 (2003)). According to the Company, the Department specifically considered, and rejected, the inclusion of indirect retail costs (e.g., customer service and billing) in basic service rates, finding those costs to be related to the provision of distribution service, and not basic service (Company Brief at 204 & n.33, citing D.T.E. 02-40-B at 17). Thus, the Company argues that Direct Energy's recommendations are inconsistent with Department precedent and that no adjustment to the Company's BSAP is warranted (Company Brief at 205-207, citing Exh. DPU-PP-17; D.T.E. 02-40-B at 18; G.L. c. 164, § 1B). Further, the Company asserts that because all electric distribution companies and their customers would be affected by any change in Department policy concerning basic service costs, any consideration of

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[251] Direct Energy rejects any notion that its recommendations are (1) inconsistent with Department precedent; (2) unnecessary given the current level of customers receiving competitive supply service in the Company's service area; and (3) unnecessary due to the Company's Purchase Receivables Program (Direct Energy Brief at 21-24, citing Provision of Default Service, D.T.E. 02-40-B (2003); Direct Energy Reply Brief at 1-3). Direct Energy argues that there is no evidence that its recommendations would have any negative impact on the Company's business, pricing, customers, or otherwise (Direct Energy Reply Brief at 4).

implementing Direct Energy's recommendations should be conducted in a generic proceeding in which all stakeholders can participate (Company Brief at 207).

C. Analysis and Findings

1. Introduction

In D.T.E. 02-40-B at 15, the Department recognized that basic service may act as a barrier to the development of competition so long as retail competitive suppliers must recover all of their costs through the prices they charge customers, while distribution companies are able to recover some of their basic service related costs through their distribution rates. Thus, the Department found that basic service rates should include all costs of providing basic service to allow competitive suppliers a fair and reasonable opportunity to compete for basic service customers. D.T.E. 02-40-B at 14.

Specifically, the Department found that because basic service prices collect the supply component of wholesale costs, all supplier-related wholesale costs should be included in basic service prices. D.T.E. 02-40-B at 16. Further, the Department found that procurement-related wholesale costs should be included in basic service rates. D.T.E. 02-40-B at 16. Procurement-related wholesale costs are associated with (1) the design and implementation of the competitive bidding process, including the evaluation of supplier bids and contract negotiations, and (2) the ongoing administration and execution of contracts with suppliers, including accounting activities necessary to track payments made to suppliers. D.T.E. 02-40-B at 16. The Department reasoned that distribution companies incur these costs solely because of their obligation to provide basic service to their customers, and they would not incur these costs if they no longer had the obligation to provide basic service. D.T.E. 02-40-B at 16. Thus,

consistent with the policy goals of cost causation, the Department concluded that procurement-related wholesale costs should be included in the calculation of basic service prices. D.T.E. 02-40-B at 16.

The Department also found that direct retail costs should be included in basic service prices, as distribution companies incur these costs strictly on behalf of its basic service customers. D.T.E. 02-40-B at 17. These costs are associated with (1) supply-related bad debt; (2) complying with the Department's basic service regulatory requirements, including required communications with its basic service customers; and (3) compliance with the Massachusetts renewable portfolio standards. D.T.E. 02-40-B at 17. The Department found that similar to wholesale-related costs, a distribution company would not incur these costs if it no longer had the obligation to provide basic service to its customers. D.T.E. 02-40-B at 17.

Finally, the Department distinguished direct retail costs from indirect retail costs, which are associated with services and activities that a distribution company provides to all of its customers alike (i.e., basic service and competitive supply). D.T.E. 02-40-B at 17. In particular, indirect retail costs are associated with the provision of customer service and billing to basic service customers, and the reporting of basic service customers' load to ISO-NE. D.T.E. 02-40-B at 17. The Department found that a distribution company would continue to provide these services, and incur these costs if it no longer had the obligation to provide basic service to its customers. D.T.E. 02-40-B at 17.[252] Thus, the Department determined that these

[252] Viewed from a different perspective, if a basic service customer were to switch to a competitive supplier, the customer would continue to receive the same level of customer service, billing, and load reporting services from the distribution company. D.T.E. 02-40-B at 17.

services are distribution related, rather than basic service related. D.T.E. 02-40-B at 17. Accordingly, the Department concluded that indirect retail costs should not be included in the calculation of basic service prices. D.T.E. 02-40-B at 17-18.

2. Allocation of Basic Service Costs

The Department has reviewed the voluminous record concerning the Company's proposed assignment of costs to the BSAP and Direct Energy's recommendations that we discuss below (Exhs. DE-FL-1, at 17-22; DE-FL-Rebuttal-1, at 4-12; NG-PP-Rebuttal-1, at 57-62; DPU-3-14; DE-1-1; DE-1-2; DE-1-3; DE-2-2; DE-2-3 & Att.; DPU-DE-1-1 through DPU-DE-1-10 (Revised); NG-DE-1-1; Tr. 8, at 1225-1262; Tr. 11, at 1611-1676; NG-5; RR-DPU-30 through RR-DPU-40).

First, we address the Company's proposed assignment of costs to the BSAP. The Company proposes to collect approximately $580,000 through the BSAP, which represents a variety of costs associated with administering basic service (Exh. NG-PP-17). Direct Energy states that this amount translates into about two or three mid-level utility employees to manage the basic service business, which is unreasonable for a company the size of National Grid (Exh. DE-FL-1, at 9-10). According to Direct Energy, it is more reasonable to expect 75 or more employees to administer basic service (Exh. DE-FL-1, at 11). Direct Energy also states that the assignment of these costs is inconsistent with the Company's internal policies and the Department's Standard of Conduct (Exh. DE-FL-1, at 11-16).

Upon review of the record and consideration of the arguments of the parties, we find that National Grid provided persuasive evidence to demonstrate that the costs attributable to administrating basic service are commensurate with the scope of work performed by Company

personnel (Exh. NG-PP-17; RR-DPU-31 & Atts.; RR-DPU-32; RR-DPU-33 & Atts.; RR-DPU-34 & Att.; RR-DPU-35 & Att.).[253] Therefore, we are not convinced that the amounts assigned to the BSAP, particularly for legal and regulatory or executive functions, need to be modified.[254] Further, we conclude that Direct Energy's recommended allocation percentages for legal and regulatory costs and executive costs are not appropriate because they are based on questionable assumptions and simplifications (Exh. DE-FL-1, at 20-21). Based on these considerations, we are not persuaded by Direct Energy's arguments that the costs associated with administering basic service are understated.

Next, we address Direct Energy's arguments regarding allocating additional costs to the BSAP. With respect to wholesale procurement costs, Direct Energy argues that National Grid assigns only "a portion" of costs to the BSAP, and fails to indicate what portion it allocated to the BSAP (Direct Energy Brief at 12, citing Exh. DE-2-2; see also Exhs. DE-FL-1, at 17; DE-FL-Rebuttal-1, at 6; DPU-DE-1-2). We disagree with this characterization. Rather, the record shows that National Grid assigns to the BSAP "the portion" attributable to the Company, as opposed to the portion attributable to its affiliate, Narragansett Electric Company (Exh. DE-2-2; see also RR-DPU-30, Att.) (emphasis added). Further, National Grid provided the percentage breakdown between the costs allocated to the Company and its affiliate (RR-DPU-30,

253 For example, we note that a core function associated with administering basic service – the quarterly solicitation process for basic service procurement – is relatively perfunctory in nature, as the Company uses standardized documents that require little if any updating or modifying from one issuance to the next (RR-DPU-32).

254 The Company indicates that executive time associated with basic service functions does not occur on a filing-to-filing basis, but on an annual basis (RR-DPU-40, at 2).

Att.). Thus, we are not persuaded that the Company improperly assigned wholesale procurement costs to the BSAP.

Additionally, Direct Energy recommends an allocation to the BSAP of at least 57 percent of the billing system and related billing costs and 25 percent of customer care costs (Direct Energy Brief at 12, 14; Exh. DE-FL-1, at 17-21). The Department has clearly set forth the types of costs that are included for recovery through the BSAP and those that should be excluded. D.T.E. 02-40-B at 16-18. In particular, indirect retail costs, such as costs "associated with the provision of customer service and billing to [basic] service customers," are not included in the calculation of BSAP prices. D.T.E. 02-40-B at 17. Therefore, based on Department precedent, the Company is not required to allocate billing and billing-related costs and customer care costs to the BSAP.

Given that the Company properly assigned costs to the BSAP, we find that the Company's allocation process was not inconsistent with any of its internal cost allocation policies. Further, we find that the Company's assignment of costs does not violate the Department's Standards of Conduct. In this regard, we are not persuaded that administrating basic service results in an affiliate arrangement with the Company in the context of 220 C.M.R. § 12.00. In particular, we note that electric distribution companies are mandated to provide a basic service offering to customers. G.L. c. 164, § 1B(d). Moreover, basic service is not sold or marketed on a competitive basis, and no profit is earned by the Company.

3. Conclusion

Based on the record and all of the above considerations, we find that the Company's proposed assignment of costs to the BSAP is reasonable and appropriate. As such, we accept

National Grid's proposal to collect $24,146,875 in test year basic service-related costs through the BSAP, and we direct the Company to revise its BSAP tariff accordingly. Regardless of the specific outcome offered here, however, the Department reemphasizes its commitment to developing the competitive supply market in order to offer customers more diverse products, price certainty, and lower prices. In this regard, we recognize the importance of fully identifying and accounting for all of the direct costs incurred in the procurement, administration, and billing of basic service. The Department looks forward to future opportunities to work with suppliers and the supplier industry groups to learn from other markets, adopt best practices, and continue to develop a fair and competitive market in the commonwealth.

XII. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid calculates its overall cost of capital, or WACC, at 8.13 percent, representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exhs. NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev.3)). This rate is based on: (1) a proposed capital structure that consists of 47.93 percent long-term debt, 0.09 percent preferred stock and 51.98 percent common equity; (2) a proposed cost of long-term debt of 5.56 percent; (3) a proposed cost of preferred cost of 4.44 percent; and (4) a proposed ROE of 10.50 percent (Exhs. NG-RBH-1, at 2-3; NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev.3)).

The Attorney General calculates a combined WACC of 7.09 percent developed using an ROE of 8.50 percent (Exh. AG-JRW-1, at 4). Below, we examine: (1) the Company's capital structure and cost of debt; (2) the respective proxy group selections used by the parties in supporting their proposed ROEs; and (3) the appropriate ROE.

B. Capital Structure and Cost of Debt

1. Company Proposal

National Grid relies on a consolidated MECo and Nantucket Electric capital structure (Exhs. NG-RBH-1, at 57-58; NG-RBH-10). As of June 30, 2015, the end of the test year, MECo's capital structure consisted of $797,828,000 in long-term debt, $2,259,000 in preferred stock, and $2,231,018,000 in common equity (Exh. NG-RBH-10). These balances produce a capital structure consisting of 26.32 percent long-term debt, 0.07 percent preferred stock, and 73.6 percent common equity (Exh. NG-RBH-10). As of that same date, Nantucket Electric's capital structure consisted of $51,665,000 in long-term debt and $47,239,000 in common equity (Exh. NG-RBH-10). These balances produce a capital structure consisting of 52.24 percent long-term debt and 47.76 percent common equity (Exh. NG-RBH-10).

National Grid has incorporated proposed changes to the test year-end capitalization balances for both MECo and Nantucket Electric. MECo's proposed long-term debt balance of $1,235,000,000 incorporates the removal of unamortized debt issuance expenses of $2,171,945, as well as the issuance of $435,000,000 in long-term debt associated with the Department's approval in Massachusetts Electric Company, D.P.U. 15-144 (2016) of the issuance of up to $784,000,000 from time to time through March 31, 2018 (Exhs. NG-RBH-1, at 57-58; NG-RBH-10; AG-5-23, Att.; at 3; Tr. 4, at 498-499). MECo's pro forma common equity balance of $1,339,156,000 incorporates the removal of $1,008,243,998 in goodwill and $5,061,963 in accumulated other comprehensive income, along with the infusion of $90,000,000 in equity capital from National Grid's parent company (Exhs. NG-RBH-1, at 57-58; NG-RBH-10; AG-5-23, Att.; Tr. 4, at 498-499). The Company attributes the simultaneous debt

issuance and addition of equity capital as part of its effort to keep the Company's capital structure reasonably balanced (Exhs. NG-RBH-10; AG-5-20; Tr. 4, at 498-499).

Nantucket Electric's adjusted long-term debt balance of zero incorporates the removal of $13,300,000 in debt dedicated to the financing of the first undersea cable project, $38,000,000 in debt dedicated to the second undersea cable project, and $360,000 principal amount outstanding as of June 30, 2015, associated with the Massachusetts Development Finance Agency's Electric Utility Revenue Bonds Series 2004 that matured on March 1, 2016 (Exh. NG-RBH-10). Nantucket Electric's adjusted common equity balance of $31,444,000 incorporates the removal of $15,705,556 in goodwill and $89,414 in accumulated other comprehensive income (Exhs. NG-RBH-1, at 58; NG-RBH-10; AG-5-23, Att. at 3).

Based on these adjustments, National Grid proposes a capital structure for the combined MECo and Nantucket Electric operations consisting of $1,235,000,000 in long-term debt, $2,259,000 in preferred stock, and $1,339,156,000 in common equity, for a total capitalization of $2,576,414,000 (Exhs. NG-RBH1, at 3; NG-RBH-10; NG-RRP-8, at 5 (Rev. 3)). These balances produce a capital structure consisting of 47.93 percent long-term debt, 0.09 percent preferred stock, and 51.98 percent common equity (Exhs. NG-RBH1, at 3; NG-RBH-10; NG-RRP-8, at 5 (Rev. 3)). The Company proposes a rate of 5.56 percent for its long-term debt and 4.44 percent for its preferred stock (Exhs. NG-RRP-2, at 33 (Rev. 3); NG-RRP-8, at 5 (Rev. 3)).

The Attorney General accepted the Company's proposed capital structure and cost of long-term debt, but noted that the Company's proposed capitalization has more equity, and, therefore, less financial risk than the capitalization ratios of the companies in the Attorney

General's proxy group (Exhs. AG-JRW 1, at 27-28; AG-JRW-4, at 1). No other party commented on the Company's capital structure and cost of debt.

2. Analysis and Findings

a. Capital Structure

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. The WACC is used to calculate the return on rate base for calculating the appropriate debt service and return on investment for the company to be included in its revenue requirement. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 17-18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986).

The Department normally will accept a company's test year end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure and normally will accept the utility's test year end capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428 429 (1971); D.P.U. 1360, at 26 27; Blackstone Gas Company, D.P.U. 1135, at 4 (1982); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

Regarding the Company's exclusion of $2,171,945 in unamortized debt issuance expenses, no party contested this adjustment. The Department has found that the appropriate

ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. D.P.U. 92-78, at 91-92; D.P.U. 86-71, at 12. The Company's treatment of unamortized debt issuance costs is consistent with Department precedent. D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52. Therefore, the Department accepts the Company's proposed exclusion of unamortized debt issuance costs.

Regarding the Company's proposed exclusion of $1,029,101,931in goodwill and accumulated other comprehensive income from capitalization, no party contested these adjustments. The Department finds that the proposed removal of goodwill is consistent with Department precedent. D.P.U. 10-55, at 473-475; D.P.U. 09-39, at 338; D.P.U. 08-35, at 189; D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324. In the case of accumulated other comprehensive income, this balance sheet item does not represent "outstanding stock" as used in G.L. c. 164, § 16. Nantucket Electric Company/Massachusetts Electric Company, D.T.E. 04-74, at 21-22 (2004). Therefore, the Department accepts the Company's proposed exclusion of accumulated other comprehensive income from capitalization. D.P.U. 09-39, at 338-339.

Pursuant to the Department's approval in D.P.U. 15-144, the Company closed on the sale of $500,000,000 in 30-year long-term debt on August 5, 2016. (D.P.U. 15-144, Compliance Filing (August 31, 2016). Therefore, the Department finds that the debt issuance represents a known and measurable change to test year-end capitalization. D.P.U. 11-43, at 204-205; D.P.U. 07-71, at 122-123; D.T.E. 05-27, at 272; D.P.U. 84-94, at 52-53. Accordingly, the Department increases the Company's proposed long-term debt balance by

$65,000,000, representing the difference between the proposed inclusion of $435,000,000 approved in D.P.U. 15-155 and the actual issuance of $500,000,000.

National Grid has excluded all of Nantucket Electric's outstanding debt from capitalization (Exh. NG-RBH-10). The $360,000 in MDFA bonds matured on March 1, 2016, and, therefore, they no longer are on Nantucket Electric's balance sheet (Exhs. NG-RBH-10; AG-5-23, Att. at 3). The Department finds that the redemption of the MDFA bonds is a known and measurable change to the Company's test year-end capitalization. D.P.U. 11-43, at 204-205; D.P.U. 10-114, at 289; D.P.U. 90-121, at 157. Turning to the exclusion of $51,300,000 in bonds used to finance Nantucket Electric's underwater cables, the costs of these underwater cables, including financing costs, are being recovered through a separate mechanism. Nantucket Electric Company, D.T.E./D.P.U. 06-106-A (2007). Therefore, the Department accepts the proposed elimination of Nantucket Electric's test year-end long-term debt balance from the Company's capitalization.

Turning to the $90,000,000 capital contribution to MECo, the Department finds that National Grid USA capital contribution was intended to fund the Company's operations and to create a more balanced capital structure after the issuance of MECo's long-term debt, planned at that time to be $435,000,000 (Tr. 4, at 498-499). The Department finds that the $90,000,000 capital contribution is a known and measurable change to test year-end capitalization. D.P.U. 15-80/D.P.U. 15-81, at 252; D.P.U. 14-150, at 316-317; D.P.U. 10-70, at 241; D.P.U. 07-71, at 122. Therefore, the Department accepts this proposed adjustment to the Company's capital structure.

Notwithstanding our acceptance here, the Department recognizes that a parent company capital contribution is not subject to regulatory review under a discernible standard. For example, stock issuances by the Company would be subject to the test under G.L. c. 164, § 14, as to whether the contributions were reasonably necessary to accomplish some legitimate purpose in meeting a company's service obligations. See Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 395 Mass. 836, 841 842 (1985), citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 394 Mass. 671, 678 (1985). Although parent holding companies can be a source of financial strength to subsidiaries, capital contributions to a subsidiary outside of the regulatory review process could have consequences where the adjustment to the subsidiary's capital structure results in a higher rate of return. We will, however, continue to examine parent holding company capital contributions for potential adverse rate effects.[255] D.P.U. 10-70, at 242.

Based on the foregoing analysis, the Department shall use a long-term debt balance of $1,300,000,000, a preferred stock balance of $2,259,000, and a common equity balance of $1,339,156,000 to determine National Grid's capital structure. As shown on Schedule 5 of this Order in Section XV below, the use of these balances produces a capital structure consisting of 49.22 percent long-term debt, 0.09 percent preferred stock, and 50.70 percent common equity.

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255 The capital contributions are not stock issuances as defined in G.L. c. 164, § 14 and, therefore, they are not subject to a determination under G.L. c. 164, § 14 that the contributions were reasonably necessary to accomplish some legitimate purpose in meeting a company's public service obligations. D.P.U. 10-70, at 241-242, citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 395 Mass. 836, 842 (1985), Fitchburg Gas and Electric Light Co. v. Department of Public Utilities, 394 Mass. 671, 678 (1985).

b. Cost of Debt and Preferred Stock

Regarding the Company's proposed costs of long-term debt and preferred stock, no party commented on the proposed rates. Costs associated with the issuance of long-term debt, such as issuance costs, debt discounts, and other related expenses, are necessary operating expenses and are expected to occur from time to time as long-term debt is issued by a company. D.P.U. 10-114, at 294; D.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. See D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161.

National Grid provided the calculations supporting the cost of its long-term debt and preferred stock (Exh. AG-5-23, Att.). We find that the Company calculated the cost of its 5.90 Percent Senior Notes and preferred stock in a manner consistent with Department precedent. D.T.E. 01-56, at 97-100. For the debt issued pursuant to D.P.U. 15-144, the Company assumed a nominal interest rate of 4.74 percent, and an effective rate of 4.77 percent (Exhs. NG-RBH-12; AG-5-2, Att. at 2). Based on the actual issuance of $500,000,000 in long-term debt associated with D.P.U. 15-144 at a nominal interest rate of 4.004 percent, the Department has recalculated the Company's cost of long-term debt provided in Exhibit AG-5-23 using the $500,000,000 principal balance, the 4.004 percent nominal interest rate, and $136,000 representing the annual amortization of issuance costs. Based on this recalculation, the effective interest rate associated with the debt issued in D.P.U. 15-144 is 4.031 percent,[256] which when combined with Massachusetts Electric's 5.90 Percent Senior Notes, produces an overall

[256] (($500,000,000 x 4.004 percent) + $136,000) / $500,000,000 = 4.031 percent.

weighted average cost of debt of 5.21 percent.[257] Accordingly, the Department finds that the Company's effective cost of long-term debt is 5.21 percent. The Department also finds that the effective cost of preferred stock is 4.44 percent. We address the Company's proposed 10.50 percent cost of equity in the following sections.

C. Proxy Groups

1. Company Proxy Group

National Grid is a wholly owned subsidiary of National Grid plc. and is not publicly traded (Exh. NG-RBH-1, at 10). Therefore, the Company has no public market for its stock. Accordingly, National Grid presents its ROE analysis using the capitalization and financial statistics of a proxy group of 25 electric companies (Exhs. NG-RBH-1, at 10-15; NG-RBH-11).[258] The Company selected its proxy group from a group of 46 companies classified as "electric utilities" by Value Line Investment Survey ("Value Line") (Exh. NG-RBH-1, at 12). From that group, National Grid chose companies that: (1) have consistently paid quarterly dividends; (2) have been covered by at least two utility industry equity analysts; (3) have investment grade senior unsecured bond and/or corporate credit ratings from Standard & Poor's Financial Services, LLC ("S&P"); (4) received at least 60 percent of their operating income from regulated electric utility operations over the past three fiscal years;

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257 (($800,000,000/$1,300,000,000) x 5.94 percent) + (($500,000,000/$1,300,000,000) x 4.031 percent) = 5.21 percent.

258 The Company removed three companies from its initial group of 25 companies: (1) Dominion Resources, (2) Duke Energy Corp., and (3) Empire District Electric Company (Exhs. NG-RBH-Rebuttal-1, at 18 n.41; Tr. 4, at 501-503; NG-RBH-Rebuttal-9). National Grid explained that these companies entered into significant corporate transactions following National Grid's initial filing, thus deviating from the Company's filing criteria used to select its proxy group (Exhs. NG-RBH-Rebuttal-1, at 18 n.41; Tr. 4, at 501-503; NG-RBH-Rebuttal-9).

(5) have reported operating income over the three most recent fiscal years representing at least 60 percent of total regulated operating income; and (6) are not currently known to be a party to a merger or other significant transaction (Exh. NG-RBH-1, at 12-13).

2. Attorney General Proxy Groups

In order to develop her rate of return recommendation for the Company, the Attorney General evaluated the return requirements of investors on the common stock of a proxy group of 26 publicly-held electric utility companies (Exhs. AG-JRW-1, at 25; AG-JRW-4, at 1). In selecting those 26 companies, the Attorney General chose companies that: (1) have at least 50 percent of revenues from regulated electric operations as reported by AUS Utilities Report; (2) are listed as an electric utility by Value Line and listed as an electric utility or combination electric and gas utility in AUS Utilities Report; (3) have an investment grade issuer credit rating by Moody's Investors Service, Inc. ("Moody's") and S&P; (4) have paid a cash dividend in the past six months, with no reductions or omissions; (5) have not been involved in an acquisition of another utility, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and (6) have analysts' five-year earnings per share ("EPS") growth rate forecasts available from Yahoo! Inc. ("Yahoo"), Thomson Reuters First Call ("First Call"), and/or Zacks Investment Research, Inc. ("Zacks") (Exh. AG-JRW-1, at 24-25). On an overall basis, the Attorney General's resulting proxy group (1) receive 82 percent of their revenues from regulated electric operations; (2) have an BBB+ bond rating from S&P,[259] and Baa1 Moody's bond

[259] Bonds rated "BBB+" by S&P exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to

rating;[260] (3) have a current median common equity ratio of 48.8 percent; and (4) have an earned ROE of 9.3 percent (Exhs. AG-JRW-1, at 26; AG-JRW-4, at 1).

The Attorney General developed financial and market data for her proxy group and the Company's proxy group[261] and applied the DCF model to arrive at a common equity recommendation for National Grid of 8.8 percent (Exh. AG-JRW-1, at 61; AG-JRW-10, AG-JRW-12). From this result, the Attorney General deducted 30 basis points to arrive at her recommended ROE of 8.50 percent for National Grid (Exhs. AG-JRW-1, at 63; JRW-10, at 1; AG-JRW-12).[262]

3. Positions of the Parties

a. Attorney General

The Attorney General states that she has evaluated the return requirements of investors on the common stock of both her proxy group and the Company's proxy group of publicly held electric utility distribution companies (Attorney General Brief at 105, citing Exhs. AG-JRW-1,

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show relative standing within the major rating categories. S&P Global Ratings available at www.standardandpoors.com.

260 Bonds rated "Baa1" by Moody's are judged to be medium-grade and are subject to moderate credit risk, and thus may possess certain speculative characteristics. The modifier "1" indicates that the obligation ranks in the higher end of its generic rating category. Moody's Investor available at www.moodys.com/Pages/amr002002.aspx.

261 The Attorney General applied her own financial inputs to the Company's proxy group, and removed four companies from the Company's initial proxy group (i.e., Dominion Resources, Duke Energy Corp., Empire District Electric Company, and Southern Company) in light of recent merger and acquisition activities undertaken by these companies (Exhs. AG-JRW-1, at 25; AG-JRW-4; Attorney General Brief at 105).

262 The Attorney General's 30-basis points risk adjustment proposal is based on the difference between the average yields for long-term utility bonds of A3 (the Company's rating) and the lower rating of Baa1 (the average rating of the Company's proxy groups) (Exhs. AG-JRW-1, at 6, 63; AG-JRW-12).

at 22-26; AG-JRW 4).[263] According to the Attorney General, the issuer credit ratings for the Company are A- according to S&P and A3 according to Moody's, while the average issuer credit ratings for both her proxy group and the Company's proxy group are BBB+ and Baa1 according to S&P and Moody's, respectively (Attorney General Brief at 106). The Attorney General contends that National Grid's credit ratings are thus one notch above the S&P and Moody's issuer credit rating of BBB+ and Baa1 assigned to the proxy groups (Attorney General Brief at 105; Tr. 4, at 1564). Therefore, the Attorney General concludes that the Company's investment risk is below that of the proxy groups (see Attorney General Brief at 107).

b. Company

National Grid argues that in determining its ROE, it has used an appropriate proxy group that includes companies that: (1) are based on valid selection criteria; (2) have sufficient financial and operating data to discern the investment risk of the Company versus the comparison group; and (3) derive at least 60 percent of operating income from regulated electric utility operations (Company Brief at 135-136, citing Exhs. NG-RBH-1, at 13-14; AG-5-15; D.P.U. 09-39, at 347-349; D.P.U. 08-35, at 176. In addition, the Company maintains that 13 of its 25 proxy companies have a capital investment cost recovery mechanism in place for at least one operating subsidiary,[264] and that all 25 proxy group companies have a revenue stabilization mechanism in place in at least one jurisdiction (Company Brief at 135-136,

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263 The Attorney General argues that when her proxy group is examined in conjunction with the Company's own proxy group, any concern as to her selection of companies is eliminated as an issue (Attorney General Reply Brief at 62-63).

264 National Grid's reference to 25 companies in its proxy group includes the three companies that were subsequently removed because of recent merger activities, as noted above.

citing Exhs. NG-RBH-1, at 41; NG-RBH-9; NG-Rebuttal-1, at 70-71; RR-DPU-19) Further, National Grid notes that the Company's proxy group selected from Value Line consist of companies that have been found comparable by the Department to other Massachusetts electric distribution companies in recent years (Company Brief at 135-136, citing D.P.U. 10-70, at 246-247, 249, 511; D.P.U. 11-01/D.P.U. 11-02, at 379-380, 384; D.P.U. 13-90 at 203, 205, 207).

4. Analysis and Findings

The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. See D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; D.P.U. 1300, at 97. The use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded. See D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded, and must be generally comparable in investment risk. D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match National Grid in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group, and that provides sufficient financial and operating data to discern the investment risk of the Company versus the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence by parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the Company. See D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482. The Department expects parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 10-114, at 299; see also D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 10-55, at 480-482.

We find that National Grid and the Attorney General each employed a set of valid criteria to select their respective proxy groups, and that they each provided sufficient information about the proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups. D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept those proxy groups to assist the Department in determining the Company's fair and reasonable cost of equity.

Our acceptance of these groups notwithstanding, we identify several factors that the Department will take into consideration in determining the appropriate ROE for the Company. First, as discussed below, both National Grid and the proxy group members have a number of reconciling mechanisms. The extent to which these particular reconciling mechanisms affect a company's cash flow will affect the evaluation of the Company's comparability to the proxy groups. Second, some of the holding companies in the proxy groups also are involved in

non-regulated businesses beyond energy distribution activities (Exhs. AG-JRW 4, at 1; AG-5-15; AG-JRW-4, at 1; AUS Utilities Reports, passim). All else being equal, these business activities potentially make these companies more risky and potentially more profitable than the Company. D.P.U. 11-01/D.P.U. 11-02, at 385; D.P.U. 10-114, at 300; D.P.U. 09-30, at 309; D.P.U. 07-71, at 135. Therefore, while we accept National Grid's and the Attorney General's proxy groups as a basis for evaluating their ROE proposals, we also will consider the particular characteristics of the Company as compared to members of the proxy groups when determining the appropriate ROE.

D. Return on Equity

1. Company Proposal

In determining its proposed ROE, the Company relied on the discounted cash flow ("DCF") model (including the constant growth and multi stage models), capital asset pricing model ("CAPM"), and the bond yield plus risk premium approach ("risk premium model") (Exhs. NG-RBH 1, at 3; NG-RBH-3; NG-RBH-4; NG-RBH-5; NG-RBH-7; NG-RBH-8). These models were applied to market and financial data developed from its proxy group (Exh. NG-RBH-1, at 10-15). Based on the results of these models and the Company's evaluation of its business risks relative to its proxy group, National Grid determined that its ROE is in the range of ten percent to 10.50 percent (Exh. NG-RBH-1, at 3).

The Company stated that its proposed ROE takes into account the implementation of decoupling and a capital investment cost recovery mechanism, the Company's particular business risks, and additional qualitative considerations to which the Department precedent has given weight in establishing authorized returns (Exh. NG-RBH-1, at 40-45, 62;

NG-RBH-Rebuttal-1, at 70-71). In this regard, the Company states that its proposed ROE of 10.50 percent is based, in part, on a proxy group of electric distribution companies that, in general, already have implemented revenue stabilization mechanisms (Exh. NG-RBH-1, at 12-14, 40-42). Thus, according to National Grid, any reduction in the ROE because the Company has implemented decoupling or capital-cost recovery mechanisms is a matter of speculation and conjecture and would ignore established legal standards requiring a return commensurate with the return for enterprises with corresponding risks (Exh. NG-RBH-1, at 7-9, 12-14, 40-42, citing Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923) ("Bluefield")).

2. Attorney General Proposal

In determining her proposed ROE, the Attorney General applied the DCF model, including the constant growth model, and the CAPM to her proxy group and she applied the same models to the Company's proxy group (Exhs. AG-JRW-1, at 4, 36-51, 52-61; AG-JRW-10; AG-JRW-11). The Attorney General initially calculated an ROE for National Grid of 8.80 percent based on an evaluation of her CAPM result of 8.10 percent and her DCF results of 8.77 percent and 8.82 percent, and then reduced the 8.80 percent by 30 basis points to recognize what she deemed to be the Company's lower risk profile as compared to the proxy groups, resulting in a proposed ROE of 8.50 percent (Exhs. AG-JRW-1, at 4, 61-63; AG-JRW-10; AG-JRW-11).

On brief, the Attorney General recommends setting the Company's ROE at 7.80 percent, which she considers to be the lowest end of her range of reasonable ROE results (Attorney

General Brief at 125-126, citing Exh. AG-JRW-1, at 61-62).[265] She proposes this ROE to account for what she identifies as a number of Company shortcomings, including its failures to: (1) conform to the Department's explicit instructions regarding the use of a split test year; (2) appropriately account for salvage value, thereby overstating the revenue requirement both in this case and the Company's previous rate case, as well as in the capital tracker mechanism; and (3) remove retired plant from plant in service accounts, resulting in an overstated depreciation expense requirement (Attorney General Brief at 125-126, citing D.T.E. 02-24/25, at 231). Further, the Attorney General notes that interest rates and capital costs remain at historically low levels and are likely to remain so for some time (Attorney General Brief at 123). The Attorney General also points out that authorized ROEs authorized by state regulators for companies under their jurisdiction have declined from 9.94 percent in 2012, to 9.68 percent in 2013, to 9.78 percent in 2014, to 9.58 percent in 2015, and to 9.68 percent in the first quarter of 2016 (Attorney General Reply Brief at 65-66, citing Exh. AG-JRW-Rebuttal-1, at 17-18).

3. Discounted Cash Flow Model

a. Company Proposal

The DCF model is based on the premise that a stock's current price is equal to the present value of the expected future cash flows that investors expect to receive (Exh. NG-RBH-1, at 17). The Company used both a constant growth and a multi-stage DCF model (Exhs. NG-RBH-1, at 17, 24; NG-RBH-3; NG-RBH-4).

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[265] The Attorney General's ROE range includes her CAPM result of 7.80 percent (8.10 percent minus the relative risk factor of 30 basis points) and the Company's DCF result of 8.52 (8.82 percent minus the relative risk factor of 30 basis points) (Attorney General Brief at 126, citing Exh. AG-JRW-1, at 61-62).

The constant growth DCF model comprises a forward looking dividend yield component and an expected dividend growth rate into perpetuity as represented by the following formula:

$$P0 = D1 / (1+k) + D2 / (1+k)2 + ... + D\infty / (1+k)\infty.$$

Where "P0" is today's stock price; "D1," "D2," etc., are all expected future dividends; and "k" is the discount rate (i.e., the investor's required ROE) (Exh. NG-RBH-1, at 17). The Company calculated the dividend yield component based on the current annualized dividends of its proxy group (Exh. NG-RBH-1, at 18). For the expected growth rate, the Company used a consensus of the Zacks, First Call, and Value Line surveys to estimate a long-term earnings growth rate (Exhs. NG-RBH-1, at 22-23; NG-RBH-Rebuttal-2).

To address what it contends are certain simplifying assumptions underlying the constant growth model, the Company also used a multi-stage DCF model (Exh. NG-RBH-1, at 24). This model employs multiple earnings growth rate and payout rate assumptions (Exh. NG-RBH-1, at 24-29). Earnings growth and payout ratio assumptions change throughout the three stages of this model (Exh. NG-RBH-1, at 24-29). In particular, the Company employed a long-term Gross Domestic Product ("GDP") growth rate of 5.23 percent (Exh. NG-RBH-1, at 29).[266]

The Company's constant growth DCF model as initially filed by the Company produced a cost of equity mean range of 9.08 to 9.27 percent (Exhs. NG-RBH-1, at 23, 63; NG-RBH-3; NG-RBH-4). National's Grid multi-stage DCF model produced a cost of equity range of 9.54 percent to 9.74 percent (Exh. NG-RBH-1, at 63). With data updated through February 29,

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266 The 5.23 percent represents the implied Nominal GDP growth rate that is derived from the following formula: ((1+ Historical Real GDP Growth) * (1+Implied Forward Inflation)) – 1 or ((1+3.25 percent) * (1+1.92 percent)) -1 (Exh. NG-RBH-Rebuttal-1, at 44 n.95). In its rebuttal testimony, the Company revised the Implied Forward Inflation rate to 2.0 percent, resulting in a GDP growth rate of 5.30 percent (Exhs. NG-RBH-Rebuttal-1, at 73; NG-RBH-Rebuttal-3; NG-RBH-Rebuttal-4)

2016, the results of the cost of common equity DCF models were as follows: a constant growth DCF model mean range of 9.13 percent to 9.37 percent and a multi-stage DCF model mean range of 9.47 percent to 9.73 percent (Exhs. NG-RBH-Rebuttal-1, at 75; NG-RBH-Rebuttal-3; NG-RBH-Rebuttal-4).

b. Attorney General Proposal

The Attorney General relies on a constant growth DCF model, reasoning that the public utility business is in the steady state (or constant growth) stage of a three-stage DCF model (Exh. AG-JRW-1, at 38). To determine the cost of equity using her constant growth DCF model, the Attorney General summed the estimated dividend yield and growth rates of her proxy group (Exh. AG-JRW-1, at 51). The Attorney General calculated the DCF dividend yield for the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices based on data supplied by Yahoo (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). Using this method, the median dividend yields for the Attorney General's proxy group range from 3.6 percent to 4.0 percent (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). Within this range, the Attorney General chose the average of the medians of 3.80 percent as the dividend yield for her electric proxy group (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2). The corresponding dividend yield for the Company's comparison group as calculated by the Attorney General is 3.85 percent, which is the average of the median dividend yields ranging from 3.7 percent to 4.0 percent (Exhs. AG-JRW-1, at 40; AG-JRW-10, at 2).

The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW-1, at 41). To annualize the expected

dividend, the Attorney General multiplied the expected dividend for the coming quarter by four and multiplied the result by one half of the expected growth rate (Exh. AG-JRW-1, at 41-42).

In developing the expected growth rate, the Attorney General relies on the historic and projected growth rates of EPS, dividends per share, and book value per share provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo, First Call, and Zacks (Exhs. AG-JRW-1, at 42; AG-JRW-10, at 3-6). Although the Attorney General assumes that EPS and dividends per share will exhibit similar growth rates over the very long term, she relies on historic and projected dividends per share and book value per share as well as internal growth to balance what she states are the shortcomings of relying solely on EPS as a proxy (i.e., an upward bias among Wall Street analysts) (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3-6). The DCF projected growth rate for her proxy and the Company's proxy group is 4.75 percent and 5.0 percent, respectively (Exhs. AG-JRW-1, at 50-51; AG-JRW-10, at 1, 3-6). The Attorney General chose the midpoint of this range or 4.875 percent as the DCF growth rate for her proxy group and the Company's proxy group (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1, 3-6)

The Attorney General added the adjusted dividend yields and the estimated growth rates to determine a cost of equity for both her proxy group and the Company's proxy group (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 8.77 percent and 8.82 percent for her proxy group and the Company's proxy group, respectively (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that her DCF-estimated cost of equity at the lowest end of her range of 7.8 percent appropriately supports her proposed ROE for National Grid (Attorney General Brief at 126, citing D.T.E. 02-24/25 at 231; Attorney General Reply Brief at 60). The Attorney General contends that her proposal takes into account the Company's issues associated with a split test year and depreciation accounting (Attorney General Brief at 126; Attorney General Reply Brief at 60).

The Attorney General asserts that the Department should reject National Grid's DCF analysis for several reasons. First, the Attorney General argues that the Company's analysis has given little weight to its constant growth DCF results, claiming that utility price-earnings ("P/E") ratios have increased, and are now high on both on an absolute and relative level (Attorney General Brief at 110; Attorney General Reply Brief at 62).

Second, the Attorney General contends that the Company's GDP growth rate of 5.23 percent used in its multi-stage DCF model is excessive, unsupported by theoretical or empirical evidence, not reflective of economic growth in the United States, and about 100 basis points above projections of long-term GDP growth (Attorney General Brief at 109-110, citing Exh. AG-JRW-1, at 68). The Attorney General claims that despite some fluctuations, nominal GDP growth rates have declined over the years and have been in the 3.50 percent to four percent range over the past five years (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Further, she argues that the compounded GDP growth rate of 6.63 percent over the 50 years since the mid-1960s belies a "monotonic and significant" decline in nominal GDP growth

rates in recent decades (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Therefore, the Attorney General concludes that a more appropriate nominal GDP growth rate figure for today's economy is in the range of four to five percent (Attorney General Brief at 112-113).

Finally, the Attorney General argues that the Company's DCF analyses are inconsistent in their use of historic versus projected data (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77). In particular, the Attorney General contends that in developing its constant growth DCF analysis, the Company ignored data on historical EPS, dividends per share, and book value per share, relying solely on what she considers to be inflated long-term EPS growth rate projections of Wall Street analysts and Value Line (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63). In addition, the Attorney General claims that, in developing a terminal DCF growth rate for its multi-stage growth DCF analysis, the Company ignored well known, long-term real GDP growth rate forecasts (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63).

ii. Company

National Grid argues that the Attorney General's DCF calculation is subjective and incapable of replication (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 24, 38; Company Reply Brief at 48). In addition, the Company contends that Attorney General's DCF recommendation improperly relies on dividend per share and book value per share growth rates, which it contends are merely derivative of earnings growth (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 34-38).

The Company disputes the Attorney General's claim that it gave insufficient weight to the results of its constant-growth DCF analysis (Company Brief at 142). Instead, the Company claims that what appears to be the issue is the Attorney General's refusal to even consider a multi-stage DCF model in setting a ROE, despite the limiting assumptions underlying the constant-growth DCF model such as the assumption that the P/E ratio stays constant in perpetuity (Company Brief at 142-143, citing Exh. NG-RBH-1, at 24). The Company adds that with P/E ratios for utilities currently at unusually high levels, it is necessary to give consideration to the result of the multi-stage DCF model when determining an appropriate level of ROE (Company Brief at 143, citing Exh. RBH-1-Rebuttal-1, at 23).

In addition, National Grid dismisses the Attorney General's contention that the EPS growth rate estimates relied on by the Company were biased (Company Brief at 143). First, the Company asserts that litigation and new financial regulations in 2003 helped neutralize analysts' conflicts of interest while removing bias in the median forecast errors (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31). Second, the Company maintains that the Department also has noted a lack of pronounced bias in the EPS forecasts for utilities (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31; D.P.U. 13-75, at 302). Third, the Company maintains that regardless of analysts' forecasts, investor expectations are more important when applying the DCF model, and the DCF-estimated ROE must recognize and reflect that it is the EPS growth rate expectations of investors that drive stock prices, even if influenced by analysts' forecasts (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 20-22). Further, the Company notes that the Attorney General conceded that any bias that

may exist for utilities is at most in the range of 20 basis points (Company Brief at 143, citing Tr. 14, at 1562).

National Grid also disputes the Attorney General's assertion that the Company's proposed multi-stage DCF growth rate of 5.23 percent, based on GDP growth rate, is inappropriate because such a growth rate does not take into consideration the more recent lower trends in GDP growth or the current forecasts by economists and some federal agencies (Company Brief at 144, citing Attorney General Brief at 111-114). To support its position that its GDP-derived growth rate is appropriate, National Grid notes that the annual nominal GDP growth rate has remained relatively stable since 1990 and was greater than five percent in twelve of the last 26 years (Company Brief at 144).

Further, the Company argues that its proposed long-term growth rate is consistent with other respected economic forecasts on long-term growth (Company Brief at 144). In support of its position, National Grid asserts that a 2010 report issued by McKinsey & Company ("McKinsey Report"), relied upon by the Attorney General in developing her testimony, states that "…long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP" (Company Brief at 144; Company Reply Brief at 52). In the same report, according to the Company, it also is noted that "'[r]eal GDP has averaged 3 to 4 percent over [the] past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent" (Company Brief at 144; Company Reply Brief at 52). Therefore, the Company maintains that its proposed growth rate of 5.23 percent is supported by the McKinsey Report because its selected growth rate represents a combination of historical real GDP growth rate and a corresponding level of expected inflation, and falls within

the lower end of the five to seven percent range noted by the McKinsey Report (Company Brief at 144; Company Reply Brief at 52). Further, the Company argues that the Attorney General has not shown that the forecasts she cites are actually relied upon by investors, nor has she explained why she considers economists' near-term interest rate projections are improper while at the same time accepting their long-term real GDP growth rate projections (Company Brief at 144).

Finally, the Company maintains that it has addressed the Attorney General's concerns regarding the appropriate P/E ratio to be used in the DCF analysis by providing an additional set of multi-stage DCF scenarios that calculate the terminal values of the stocks of the companies in the proxy group using a constant average P/E ratio of 18.56 percent (Company Brief at 144-145; Exh. NG-RBH-Rebuttal-4). According to the Company, using a range of multi-stage DCF scenarios with a constant average P/E ratio fully support the Company's proposed 10.50 percent ROE (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-4).

d. Analysis and Findings

In developing their proposed ROEs, both the Company and the Attorney General use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. NG-RBH-1, at 18, 20; AG-JRW-1, at 38). This model has a number of very strict assumptions (e.g., the infinite investment horizon and dividend growth at a constant rate in perpetuity) (Exh. NG-RBH-1, at 20). These assumptions affect the estimates of the cost of equity. D.P.U. 10-114, at 312; D.P.U. 09-39, at 387.

Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30,

at 357-358. Specifically, the DCF model includes an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 253; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the results of both the Company's and the Attorney General's DCF models. The Attorney General's DCF model places less emphasis on analyst forecasts of EPS growth rates which, to some extent, compensates for this circularity (see Exh. AG-JRW-1, at 46-47).

The Company and Attorney General use different data sources to estimate the dividend yield and growth rates (Exhs. NG-RBH-1, at 18-19; AG-JRW-1, at 36-46). The Company uses the Bloomberg Professional ("Bloomberg") dividend estimates, adjusting them by one-half of the growth rate, while the Attorney General calculates the dividend yield by applying one-half of the growth rate to a six-month average dividend yield (Exhs. NG-RBH-1, at 19; NG-RBH-3; AG-JRW-1, at 42, 51; AG-JRW-10, at 1). The Department finds that both the Company's and the Attorney General's approaches are logical and reasonable. Further, there is no evidence to establish that investors rely overwhelmingly on one approach over the other. Therefore, we find that both approaches provide a credible basis for evaluating a determination of the Company's allowed ROE.

In addition, the Company and the Attorney General use different growth rates in their respective DCF analyses (Exhs. NG-RBH-1, at 29-30; NG-RBH-4; NG-RBH-Rebuttal 4; AG-JRW-1, at 50-51; AG-JRW-10, at 1). Determining the appropriate long-term growth expectations of investors in a DCF analysis can be difficult and controversial (see Exhs. NG-RBH-1, at 20; AG-JRW-1, at 39). The Company relies on a forward looking growth analysis using EPS, based on the assumption that investors form their investment

decisions based on expectations of growth in earnings and not dividends (Exhs. NG-RBH-1, at 22; NG-RBH-Rebuttal-1, at 38; NG-RBH-Rebuttal-2). Conversely, the Attorney General bases her growth rate on a historical and forward looking growth analysis using EPS, dividends per share, book value per share, and retention growth rates (Exh. AG-JRW-1, at 42-44). The Attorney General emphasizes dividend growth over earnings growth because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3, 4, 5). The Department has found that investors' heavy reliance on EPS forecasts give credence to the Attorney General's argument that investors are aware of upward biases. D.P.U. 13-75, at 302. Accordingly, the Department will take these biases into consideration in evaluating the Company's DCF analysis.

4. Capital Asset Pricing Model

a. Company Proposal

The Company used the CAPM to estimate the cost of equity for its proxy group (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7). The application of the Company's CAPM resulted in eight individual costs of equity estimates, ranging from 9.46 percent to 11.17 percent (Exhs. NG-RBH-1, at 34, 63; NG-RBH Rebuttal-1, at 76; NG-RBH- Rebuttal-7). National Grid considered these results when determining its proposed ROE (Exhs. NG-RBH-1, at 6; NG-RBH-Rebuttal-7).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. In the CAPM, the required rate of return on common equity is equal to the expected risk free rate of return plus a premium for the implicit systematic risk of the security (Exh. NG-RBH-1, at 31). There are three necessary components to calculate the cost of equity in

the CAPM: (1) an expected risk free rate of return; (2) the market risk premium; and (3) the beta, a measure of systematic risk (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7).

The Company used the current and forecasted 30-year Treasury bond yields to arrive at current, near-term, and long-term risk free rates (Exhs. NG-RBH-1, at 32; NG-RBH-5; NG-RBH-6; NG-RBH-7). The CAPM market risk premium is derived from the total return on the overall market minus the risk free rate of return. The Company developed ex ante market risk premiums based on data from both Bloomberg and Value Line by calculating their respective estimated market required returns less the Treasury bond yield (Exhs. NG-RBH 1, at 32-33; NG-RBH-5; NG-RBH-7).

The Company obtained beta coefficients for its proxy group from Bloomberg (0.653) and Value Line (0.75) (Exhs. NG-RBH-1, at 33; NG-RBH-6). Using these beta coefficients in combination with separate Bloomberg and Value Line data and current, near term, and long-term risk free rates, National Grid calculated four Bloomberg market DCF derived CAPM results and four Value Line market DCF derived CAPM results (Exhs. NG-RBH-1, at 34; NG-RBH-7).

b. Attorney General Proposal

The Attorney General used a traditional CAPM approach in which the cost of equity is equal to the sum of the interest rate on risk free bonds and an equity risk premium (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in stocks) (Exhs. AG-JRW-1, at 52; AG-JRW-11, at 1). The Attorney General's CAPM analysis resulted in a cost of equity of 8.10 percent (Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

In her analysis, the Attorney General used the upper bound of the six-month average yield on 30-year Treasury bonds (i.e., four percent) as the risk free rate (Exhs. AG-JRW-1, at 54; AG-JRW-11). The Attorney General then calculated an estimated market risk premium of 5.5 percent, based on the midpoint of a range of market risk premiums of four percent to six percent (Exhs. AG JRW-1, at 59; AG-JRW-11, at 1, 5 6). To calculate the beta coefficient, the Attorney General performed a regression analysis of the returns of the companies in her proxy group against the return of the S&P 500 representing the market, resulting in a median beta coefficient of 0.75 percent (Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1, 3). The Attorney General multiplied the estimated market risk premium of 5.5 percent by the beta coefficients of 0.75 percent to produce an expected equity risk premium of 4.10 percent (see Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1). The risk free rate of four percent added to the expected risk premiums of 4.10 percent results in a cost of equity of 8.10 percent (see Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's CAPM analysis produces results that vastly overstate long-term growth projections (Attorney General Brief at 119). According to the Attorney General, the Company's primary errors are with its use of inflated market risk premiums of 10.05 percent and 10.59 percent (Attorney General Brief at 120). Further, the Attorney General contends that the Company's long-term EPS growth rates of 11.12 percent and 10.80 percent are based on overly optimistic and upwardly biased Wall Street analysts' forecasts (Attorney General Brief at 117-119 citing Exh. AG-JRW-1, at 79-80).

In contrast, the Attorney General maintains that long-term economic, earnings, and dividend growth rates in the United States indicate that historical long-term growth rates are in the five percent to seven percent range (Attorney General Brief at 118). Moreover, the Attorney General asserts that more recent trends suggest lower future economic growth than the long-term historic GDP growth, in the range of four percent to five percent for today's economy, and notes that the projected long-term GDP growth rate forecasts by economists and government agencies are currently in the four percent to five range as well (Attorney General Brief at 118, citing Exh. AG-JRW-1, at 73-75).

Finally, the Attorney General argues that given current low inflation and limited economic growth, the Company's projected earnings growth rates, implied expected stock market returns, and equity risk premiums are not indicative of the realities of the economy (Attorney General Brief at 119, citing Exh. AG-JRW-1, at 80). Based on the above, the Attorney General asserts that the Department should reject the Company's proposed CAPM analysis and recommendations (Attorney General Brief at 120).

ii. Company

The Company argues that the Attorney General's CAPM calculation must be rejected because the equity risk premium she relied on assumes market returns that do not make theoretical or practical sense (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-1, at 54). Further, the Company contends that the Attorney General's CAPM analyses do not reflect fundamental risk-return relationships (Company Brief at 145).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 168). Using the same

analysis as discussed above regarding the DCF model, the Company maintains that recent evidence does not support any upward bias in analysts' forecasts in particular for electric utilities (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-1, at 34).

d. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of a number of questionable assumptions that underlie the model. D.P.U. 10-114, at 318; D.P.U. 10-70, at 270; D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54. For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk free rate and has found that the coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67 (Phase I) at 182-184.

The Attorney General's CAPM analysis employs a risk free rate of four percent, using the upper bound of the prior six months' 30-year Treasury bond rates as a proxy (Exh. AG-JRW-1, at 54, 60-61). Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows (Exh. AG-JRW 1, at 21-22). Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk free rate over the long term and, thereby, understate the required ROE. D.P.U. 14-150, at 350; D.P.U. 12-25, at 427; D.P.U. 11 01/D.P.U. 11-02, at 416.

The Company develops a range of risk free rates from 2.68 percent to 3.35 percent, relying on the current 30-year Treasury bond rates as published in Bloomberg, as well as the near- and long-term projected 30-year Treasury bond rates based on interest rate forecasts

published in Blue Chip Financial Forecasts (Exhs. NG-RBH-Rebuttal-1, at 75; NG-RBH-Rebuttal-7). The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate. D.P.U. 13-75, at 314.

The Attorney General calculated a market risk premium of 5.5 percent, based on her analysis of numerous surveys of financial professionals, including financial forecasters, chief financial officers, and academics (Exhs. AG-JRW-1, at 59-60; AG-JRW-11, at 1). Alternatively, the Company calculates a revised market risk premium range of 8.46 percent to 11.62 percent based on DCF analyses (Exhs. NG-RBH-Rebuttal-1, at 76; Sch. NG-RBH-Rebuttal-7). Because the CAPM is considered an ex-ante, forward looking model that recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk, the Department finds that the Company's approach based on DCF analyses is less reliable than the survey results of financial professionals. D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314.

The Company asserts that because investors rely on financial analysts' forecasts in making investment decisions EPS forecasts are superior to other measures of growth in predicting stock prices (see Exh. NG-RBH-1, at 21). The Department notes that a 2015 survey of over 8,000 academics, financial analysts, and companies estimates a market risk premium of 5.5 percent, which is far lower than the 8.46 percent to 11.62 percent range used in National Grid's analysis (Exhs. NG-RBH-Rebuttal-1, at 76; NG-RBH-Rebuttal-7; AG-JRW-1, at 58;

AG-JRW-11, at 6). Accordingly, the Department places more weight on the Attorney General's approach to developing a market risk premium.

Based on the above considerations, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE. Based on the above considerations, to the limited extent that we rely on CAPM estimates, the Department gives more weight to the Attorney General's proposed CAPM.

5. Risk Premium Model

a. Company Proposal

The risk premium model is based on the concept that investing in common stock is riskier than investing in debt and, therefore, investors require a higher rate of return for equity (Exh. NG-RBH-1, at 34).[267] In the bond yield plus risk premium model used by the Company, the cost of equity is derived by calculating a risk premium over the returns available to bondholders (Exh. NG-RBH-1, at 34). Based on data from 1,456 electric utility proceedings between January 1, 1980 and September 30, 2015, the Company derived a risk premium analysis producing a cost of equity range of 10.05 percent to 10.59 percent applicable to its proxy group (Exh. NG-RBH-8).

National Grid calculated the risk premium as the difference between: (1) actual authorized returns using data from 1,456 electric utility rate proceedings between January 1,

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267 The equity risk premium is defined as the incremental return that an equity investment provides over the risk-free rate (Exhs. NG-RBH-1, at 34; NG-RBH-8). The risk premium method of determining the cost of equity recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: (1) determine the historical spread between the return on debt and the ROE; and (2) add this spread to the current debt yield to derive an estimate of current equity return requirements. D.P.U. 13-75, at 316 n.201.

1980, and September 30, 2015; and (2) the then prevailing long-term Treasury yield (i.e., 30-year bonds) (Exhs. NG-RBH-1, at 35; NG-RBH-8). To account for the forward looking return and interest rates, National Grid calculated the average return period between the filing of this case and the approval of rates, as well as the level of interest rates during the pendency of the proceedings (Exh. NG-RBH-1, at 35). To assess the relationship between the 30-year Treasury yield and the equity risk premium, the Company relied on a statistical analysis that concluded there was a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium (Exhs. NG-RBH-1, at 36-37; NG-RBH-8).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's application of the bond yield plus risk premium model is flawed for three reasons (Attorney General Brief at 120). First, the Attorney General argues that the Company's method produces an inflated measure of the risk premium because it is based on historic authorized ROEs less Treasury yields, and then is applied to projected Treasury yields that always are forecasted to increase (Attorney General Brief at 121). Second, the Attorney General contends that the Company's overall approach improperly uses authorized ROEs as an input to the model, and that such an approach is more of a gauge of public utility commission behavior than a consideration of investor behavior (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 83-84). In this regard, the Attorney General claims that in setting ROEs, regulatory commissions evaluate capital market data such as dividend yields, expected growth rates, interest rates, as well as rate case specific regulatory information (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 83-84). Further, the Attorney General

argues that the Company's analysis overstates the risk premium because National Grid estimates the risk premium using historical interest rate data, and then applies this data to forecasted interest rates (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 82).

Finally, the Attorney General argues that a comparison of the Company's risk premium results to actual authorized ROEs for electric utility companies confirms the errors in the Company's approach (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). The Attorney General notes that authorized ROEs for electric distribution companies have decreased in recent years, from 10.01 percent in 2012, to 9.8 percent in 2013, to 9.76 percent in 2014, and 9.58 percent in 2015 (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). Moreover, the Attorney General asserts that National Grid's long-term projected Treasury bond yield of 4.9 percent is 200 basis points above current yields and, therefore, is not reasonable (Attorney General Brief at 121, citing Exh. JRW-1, at 82).

ii. Company

National Grid disputes the Attorney General's argument that the Company's bond yield plus risk premium approach gauges regulatory commission behavior rather than investor behavior (Company Brief at 146-147). The Company argues that regulatory decisions reflect market based analyses (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57). Further, the Company contends that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements. For these reasons, the Company asserts that authorized returns are a reasonable measure of investor required returns (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57).

The Company notes that in the past the Department has viewed the risk premium approach as a "supplemental approach" in determining the level of ROE (Company Brief at 147, citing D.P.U. 07-71, at 137). Based on the above, National Grid argues that the Department should at least supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 147).

c. Analysis and Findings

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. See D.P.U. 10-114, at 322; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a supplemental approach to other ROE models. D.P.U. 10-114, at 322; D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In the instant case, the Company's risk premium analysis is flawed. First, the Department has recognized the circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. In addition, the Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis, and we are not convinced that the Company's substitution of projected Treasury debt yields provides a better approach. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Company continues

to use projected cost of Treasury debt in this model, suggesting that the risk premium approach is forward-looking and, therefore, using the forward-looking approach is appropriate (see Exh. NG-RBH-8). The Department disagrees. The risk premium model is not a forward looking approach, and is, instead, based on current market conditions. See D.P.U. 13-75, at 319; D.P.U.12-25, at 433. Accordingly, the Department finds that current treasury yields are more appropriate than projected yields for use in a risk premium analysis. For these reasons, the Department finds that National Grid's risk premium model overstates the required ROE for the Company.

E. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 692-693 and Hope at 603. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The Company recommends that the Department approve an ROE of 10.50 percent (Exhs. NG-RBH-1, at 3; NG-RBH-Rebuttal-1, at 77). The Attorney General recommends an ROE of 7.80 percent (Attorney General Brief at 125-126, citing Exh. JRW-1, at 61-62). The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11, cert. denied, 439 U.S. 921 (1978); Boston Gas Company v. Department of Public Utilities, 359

Mass. 292, 305-306 (1971).[268] Thus, in determining an appropriate ROE for National Grid, the Department first evaluates the quantitative factors presented in this case.

In support of its recommended ROE, National Grid has presented quantitative analyses using the DCF model, the CAPM, and a bond yield plus risk premium approach, each incorporating the financial data of its proxy group. The Attorney General has presented her analyses using the DCF model and the CAPM, incorporating the financial data of both her proxy group and the Company's proxy group (Exh. AG-JRW-4, Panels A and B). The use of empirical analyses in this context is not an exact science. A number of judgments are required in conducting a model based rate of return analysis. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. D.P.U 18731, at 59. Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As discussed above, the evidence demonstrates that each equity cost model used by the Company and the Attorney General suffers from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may not be reliable for the purpose of setting the Company's ROE. For example, we

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[268] As noted above, the Attorney General proposes a ROE of 7.80 percent to account for what she identifies as a number of Company shortcomings, including its failures to: (1) conform to the Department's explicit instructions regarding the use of a split test year; (2) appropriately account for salvage value, thereby overstating the revenue requirement both in this case and the Company's previous rate case, as well as in the capital tracker mechanism; and (3) remove retired plant from plant in service accounts, resulting in an overstated depreciation expense requirement (Attorney General Brief at 125-126, citing D.T.E. 02-24/25, at 231). As discussed in Sections III and VIII.E, we decline to adjust the ROE based on these specific recommendations.

note the limitations of the DCF models used by both the Company and the Attorney General, including the simplifying assumptions that underlie the constant growth form of the model, and its element of circularity, as well as the inherent limitations in comparing the Company to publicly traded companies. In particular, we find that the Company's DCF analysis overestimates the cost of equity by minimizing the low-outlier estimates. We also find that the Attorney General's DCF model retains some elements of circularity because investor expectations depend upon regulatory decisions.

The Department further finds that the CAPM analyses relied upon by the Company and the Attorney General also are flawed because of the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums. To the extent we rely on the CAPM estimates, we give more weight to the Attorney General's analysis because the magnitude of the deficiencies within the Company's proposed CAPM, including the estimate of a market risk premium, is greater. Finally, we find that the Company's risk premium approach suffers from a number of limitations and tends to overstate National Grid's required ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise.[269] D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118;

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[269] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the

D.P.U. 18731, at 59; see also 375 Mass. 1, 15. The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

We note that a portion of the revenues of the companies in both proxy groups is derived from unregulated and competitive lines of business (Exhs. AG-5-15; AG-JRW-4, at 1; AUS Utilities Reports, passim). All else equal, this mix of regulated and unregulated operations would tend to overstate the proxy groups' risk profiles relative to that of the Company. Therefore, in applying this comparability standard, we will consider such risk differentials when weighing the results of the models used to estimate the Company's allowed ROE.

In addition, the Department granted in this Order revisions to National Grid's CIRM (formerly CapEx), which allows the Company to implement an annual rate adjustment to support the net increase in rate base arising from the annual capital additions that the Company makes to upgrade its distribution system (see Section V.D above). National Grid's CIRM, which now accounts for property tax expense, serves to reduce the Company's risks and its investors' return requirement. Although many companies in both proxy groups employ some form of infrastructure recovery mechanism, these infrastructure recovery mechanisms vary among the companies, particularly insofar as the scope of eligible investments and the timing of cost recovery (Exhs. NG-RBH-1, at 40; NG-RBH-9; AG-JRW-4). On the whole, the infrastructure recovery mechanisms for these companies are less comprehensive than the CIRM (Exhs. NG-RBH-9; AG-JRW-4).

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witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

The Department also recognizes that the Company's decoupling mechanism reduces the variability of the Company's revenues and, accordingly, reduces its risks and its investors' return requirement. See D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although many companies in both proxy groups employ some form of revenue stabilization or decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies and, on the whole, is not as comprehensive as the Company's decoupling mechanism (Exhs. NG-RBH-9; AG-JRW-4).

The Company argues that the pertinent analysis in assessing the impact of decoupling or CIRM on the Company's ROE is not to analyze whether the Company is "less risky" but rather to ascertain whether (1) the effect of the mechanism was to reduce risk below the levels faced by the Company's peers; and (2) investors knowingly reduced their return requirements as a direct consequence of the mechanism (Exh. NG-RBH-1, at 40-42; Company Brief at 139-141). We disagree. While the issue of decoupling and its overall effect on a company's ROE is not a new factor for consideration for the first time in this proceeding, and independent of whether or not investors are keen to compare National Grid's decoupling level of risk vis-à-vis the Company's peers decoupling mechanisms, the fact remains that these mechanisms reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73.

In considering National Grid's allowed ROE, the Department also takes into account the modifications to the Company's storm fund mechanism. In particular, the Department has raised the cost-per-storm threshold, excluded from storm fund eligibility any single storm event with incremental costs that exceed $30 million, and modified the carrying charge component of the

storm fund (see Section VI.D). These modifications are intended to prevent a significant storm fund deficit, provide necessary rate stability for customers, more appropriately reflect the costs associated with the storm fund balance, and help ensure that the storm fund works as intended. The Department recognizes that, on balance, these modifications tend to increase the Company's risk associated with the recovery for storm costs when compared to the storm fund approved in D.P.U. 09-39. In addition, the Department takes into account our allowance of National Grid's recovery of its test year balance of protected hardship account receivables (see Section VIII.J.3). In allowing this recovery, the Department provides for the probability of recovery to avoid an impairment of loss by National Grid through a charge to its income statement that could be required by generally accepted accounting principles. We find that this ratemaking treatment of protected hardship account balances reduces the Company's risks.

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's long-standing precedent[270]

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[270] For example, the Department has set a utility's ROE at the low end of a range of reasonableness upon a showing that a utility's management performance was deficient. D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 218-222 (company's improper handling of a billing error, failure to provide acceptable unaccounted for water report, improper flushing practices, and insufficient communication with customers warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424-426 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-340 (company activities related to Department-ordered audit warranted ROE at lower end of reasonable range); D.P.U. 08-35, at 220 (customer service deficiencies warranted ROE at lower end of reasonable range); D.P.U. 08-27, at 136, 137 (failure to conduct competitive bidding for outside consultants and provide detailed rate case expense invoices warranted ROE at lower end of reasonable range); see also D.P.U. 85-266-A/271-A at 172 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

and accepted regulatory practice[271] to consider qualitative factors such as management performance and customer service in setting a fair and reasonable ROE. With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271 A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above average or subpar management performance and customer service. See, e.g., D.P.U. 12-86, at 274-276 & n.181 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424, 427 (company shortcomings in storm response warranted ROE at lower end of reasonable range).

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed ROE of 9.90 percent is within a reasonable range of rates that will preserve the Company's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this

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271 See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE).

case.[272] In making these findings, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XIII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 330; D.P.U. 12-25, at 445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 401. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption

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[272] In setting this ROE, the Department took into consideration the amount of the storm fund assessment paid by National Grid pursuant to G.L. c. 25, § 18. See Fitchburg Gas and Electric light Company at al. v. Department of Public Utilities, 467 Mass. 768 (2014).

in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.[273]

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 331; D.P.U. 12-25, at 444-445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to each rate class through an embedded allocated cost of service study ("COSS"). The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 331; D.P.U. 12-25, at 446; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402-403.

There are four steps to develop an allocated COSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as

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[273] Effective use of energy resources means reducing the total amount of energy consumed without compromising service reliability through the use of more efficient technologies and practices, with clear and timely pricing information, as part of a sustainable energy policy. See An Act Relative to Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298.

demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based on the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446-447; D.P.U. 09-39, at 402-403.

The results of the allocated COSS are compared to the revenues collected from each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 403.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an allocated COSS, but also explicitly considers the effect of its rate structure decisions on the amount customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 403-404. To reach fair decisions

that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies — or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i). In addition, G.L. c. 164, § 94I ("§ 94I") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[274] The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above.

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[274] An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, Section 20, inserted G.L. c. 164, § 94I:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404.

B. Cost Allocation

1. Introduction

National Grid performed an allocated COSS that directly assigns or allocates, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. NG-PP-1, at 9). There are three steps to the Company's allocated COSS.

First, the Company functionalizes costs by its basic function, such as primary distribution, secondary distribution, and customer (Exh. NG-PP-1, at 13-14).[275] The primary distribution function includes costs related to substations, conductors rated 4 kilovolt ("kV") and higher, transmission, and production assets (Exh. NG-PP-1, at 10). The secondary distribution function includes costs related to conductors and other assets that move electricity from the primary system to customers' premises (Exh. NG-PP-1, at 10). The customer function includes costs related to meters, service drops, billing and collection, and any assets and activities that enable the distribution of electricity to the customer (Exh. NG-PP-1, at 10).

Second, the Company classifies each functionalized cost as demand-, energy-, or customer-related according to the system design or operating characteristics that cause them to be incurred (Exh. NG-PP-1, at 9, 15). Demand-related costs are associated with plant that is designed, constructed, and operated to meet system peak demand or non-coincident class peak demand (Exh. NG-PP-1, at 16). Energy-related costs vary with the electricity delivered to customers (Exh. NG-PP-1, at 16). Customer-related costs are incurred to attach a customer to

[275] There are separate functions for primary distribution and secondary distribution because some customers take service at primary voltages (Exh. NG-PP-1, at 14).

the distribution system, to meter and read usage, and to maintain the meter, service drop, and the customer's account (Exh. NG-PP-1, at 15). Customer-related costs are a function of the number of customers the Company serves, are incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile (Exh. NG-PP-1, at 15).

The third step is the allocation of each functionalized and classified cost element to each rate class based on cost-causation principles (Exh. NG-PP-1, at 9, 16).[276] Costs are either directly assigned or allocated to rate classes (Exh. NG-PP-1, at 16).

In allocating costs to rate classes, the Company used external and internal allocators (Exh. NG-PP-1, at 12). External allocators are developed in special studies derived from the Company's accounting, operating, and other records (Exh. NG-PP-1, at 12). Examples of external allocators are: (1) the numbers of customers in each rate class; (2) class non-coincident peak demands; and (3) historical bad debt experience for each rate class (Exh. NG-PP-1, at 13). Internal allocators are developed within the allocated COSS using a combination of external allocators and other internal allocators (Exh. NG-PP-1, at 13). The Company explains that the internal allocator for property insurance costs is based on plant investment, and therefore, plant investment must be allocated to each rate class before property insurance costs can be assigned to each rate class (Exh. NG-PP-1, at 13).

National Grid set its initial revenue requirement target for each rate class to generate equalized rates of return (Exh. NG-PP-1, at 19). This step resulted in an overall average percentage increase to existing base rates of 5.11 percent (Exh. NG-PP-1, at 21). National Grid

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276 Inherent in this third step, as discussed in the Rate Structure section, is the process of identifying an allocator that is most appropriate for costs in each classification within each function.

proposed to limit the rate increases for Rate R-4 and the street lighting rate classes to ten percent of total revenue (Exh. NG-PP-1, at 21). The Company proposed to allocate the revenue shortfall to all other rate classes based on each rate class's share of base distribution revenue (Exh. NG-PP-1, at 21).

2. Positions of the Parties

a. Attorney General

According to the Attorney General, the Company's "unit cost analysis"[277] does not accurately reflect how costs are allocated in the allocated COSS (Exh. AG-SJR-1, at 8, citing Exh. DPU-33-8, at 35). The Attorney General maintains that in the allocated COSS, the Company allocates costs for production plant, power supply expenses, demonstration and selling expense, miscellaneous expenses, and depreciation expense related to production plant using a rate class's energy consumption (Exh. AG-SJR-1, at 9 citing Exh. DPU-33-8, at 14, 16, 18, 22, 24, 25). However, the Attorney General argues that energy consumption does not appear in the Company's unit cost analysis (Exh. AG-SJR-1, at 8). The Attorney General points out that the Company incorrectly states: "the Company has classified all assets and costs as either [d]emand or [c]ustomer. The Company did not classify any asset or cost as [e]nergy" (Exh. AG-SJR-1, at 8, citing Exh. DPU-1-14).[278]

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277 The unitized cost is the cost associated with a utility function divided by the number of units of service for that function (Exh. AG-SJR-1, at 7). It also is referred to as an embedded cost analysis.

278 According to the Attorney General's analysis, the unitized demand-related cost for the residential rate class decreases from $12.90 per kW per month to $12.72 per kW per month, the customer-related costs decreases from $9.42 per month to $9.31 per month, and the unitized energy-related cost is 0.006 cents per kWh (Exh. AG-SJR-1, at 9).

Further, the Attorney General argues that the Company relies on unitized costs to estimate the cost to serve a customer (Exh. AG-SJR-1, at 9). However, the Attorney General contends that the unitized cost for the rate class will likely be different from the actual cost to serve any particular residential customer (Exh. AG-SJR-1, at 9). Therefore, the Attorney General asserts that the average cost to serve a typical customer is fair to all customers, at a given point in time, "because each customer has a fairly equal chance of being served by facilities that are more expensive or less expensive than average" (Exh. AG-SJR-1, 10).[279]

b. Acadia Center

Acadia Center argues that the economic analysis used in an allocated COSS has evolved since the electric industry was created in the United States (Acadia Center Brief at 11). According to Acacia Center, an allocated COSS misses a significant part of the overall picture for system costs (Acadia Center Brief at 11). Specifically, Acadia Center maintains that the traditional allocated COSS is no longer sufficient in rate design because the shift to cost-effective distributed energy resources is not included in the analysis (Acadia Center Brief at 11). Acadia Center contends that the impact on rates from the incorporation of distributed energy resources into a distribution system is a cutting edge topic and is worthy of consideration by the Department, as well as discussion among stakeholders (Acadia Center Brief at 11). Thus,

[279] In the Attorney General's example, she explains that if a pole is replaced on a customer's street, the customer is likely paying, in sequence: (1) less than the actual cost of service for a few initial years; (2) equal to the cost of service; and (3) less than the actual cost of service towards the end of the useful life of the pole (Exh. AG-SJR-1, at 10).

Acadia Center asserts that the value of distributed energy resources should be a part of the next evolutionary phase in the economic analysis for ratemaking (Acadia Center Brief at 11).[280]

c. Direct Energy

Direct Energy supports reform to the allocated COSS (Direct Energy Brief at 15). In particular, Direct Energy argues that the Department should require the Company to provide a new allocated COSS that allocates costs to both distribution service and basic service (Direct Energy Brief at 15).[281] Direct Energy recommends that the new allocated COSS be reflected in rates at or close in time to the point at which the Company's proposed rate increases are allowed to take effect (Direct Energy Brief at 15). Further, Direct Energy suggests that the Company should participate in a stakeholder process to review the new allocated COSS, and collectively present an agreed upon allocated COSS to the Department for approval (Direct Energy Brief at 15). Finally, Direct Energy argues that the Company should explain its experiences in allocated COSS reform in a statewide investigation on this issue (Direct Energy Brief at 15).

d. Company

According to the Company, its rate proposals are based on its allocated COSS (Company Brief at 198). National Grid asserts that its allocated COSS directly assigns or allocates each element of its revenue requirement among the rate classes in order to determine the costs of providing service to each rate class (Company Brief at 198, citing Exh. NG-PP-1, at 9). The Company notes that results from its allocated COSS at present rates show that the Company is

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280 Acadia Center contends that the benefits include capacity savings, transmission savings, reduced energy prices, and the avoided cost of compliance with greenhouse gas emission requirements (Acadia Center Brief at 11).

281 Direct Energy also raises specific issues related to the Company's recovery of basic service costs in Section XI above.

earning an overall return of 1.18 percent, with class returns varying from negative 7.86 percent to 9.86 percent (Company Brief at 200, citing Exh. NG-PP-2(a)).

3. Analysis and Findings

Pursuant to § 94I, the Department in each base distribution rate proceeding is required to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent. The Department finds that National Grid's proposal to cap the rate increase for Rate R-4 and the street lighting rate classes at ten percent of total revenue complies with § 94I (Exhs. NG-PP-4, at 2; NG-PP-1, at 21; DPU-33-8, Att. at 38 (PDF)).

The Company proposed to allocate the revenue increase above the ten percent cap using the uncapped rate classes' share of test year base distribution revenues (i.e., distribution revenues at present rates) (Exhs. NG-PP-1, at 21; NG-PP-4, at 2; DPU-33-8, Att. at 38 (PDF)). The Department's long-standing policy regarding the allocation of class revenue requirements that exceed a cap is that they should be allocated to those rate classes that do not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return. D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214. Moreover, the Department recently directed Fitchburg Gas and Electric Light Company to allocate the revenue requirement in excess of the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return instead of test year distribution revenues. D.P.U. 15-80/D.P.U. 15-81, at 302. For these reasons, and to advance the rate goals of fairness and efficiency, the Department directs the Company to allocate

the revenue requirement that exceeds the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return.

The Department notes that allocating the revenue requirement that exceeds the ten-percent rate cap based on revenue requirements at equalized rates of return still results in a significant rate increase for Rate R-4 that violates our continuity goal. Consequently, the Department directs the Company to limit the distribution rate increase for Rate R-4 to 200 percent of the overall distribution rate increase, and to allocate the remaining revenue requirement to the uncapped rate classes based on the ratio of their class revenue requirement at equalized rates of return to the sum of the class revenue requirement at equalized rates of return for all uncapped rate classes.[282]

The Department declines to adopt the Attorney General's recommended modifications to the allocated COSS. The Company functionalized all of its costs as primary distribution, secondary distribution, or customer (Exh. NG-PP-1, at 13). Costs are then classified based on system design or operating characteristics (Exh. NG-PP-1, at 15). When classifying the functionalized costs, costs classified as energy-related vary with the electricity sold to or delivered to customers (Exh. NG-PP-1, at 16). All of the assets and costs in the Company's primary and secondary distribution functions are classified as demand-related, and all of the assets and costs in the Company's customer function are classified as customer-related (Exh. NG-PP-1, at 16). Thus, none of the Company's functionalized costs were classified as

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[282] The Department makes this directive based on the allocated COSS and revenue requirement in the Company's response to information request DPU-33-8 (Exh. DPU-33-8, Att. at 22). The Department, therefore, directs the Company to apply the 200-percent cap using the allocated COSS and revenue requirements that result from our findings in this Order.

energy-related. In the class allocation step, functionalized and classified costs are then allocated among the rate classes based on causal relationships (Exh. NG-PP-1, at 16). For example, production plant and production O&M were allocated among the rate classes based on each class's test year megawatt-hour deliveries because of the causal relationship (Exh. NG-PP-1, at 16). If customers use more energy, then production plant and O&M costs will increase. Additionally, the Department notes that the Company did not change this classification and allocation method from its allocated COSS that was approved in its last rate case (Exh. DPU-1-7, Att. at 2).

Further, Acadia Center and Direct Energy allege deficiencies in the Company's allocated COSS (Acadia Center Brief at 11; Direct Energy Brief at 15). Having reviewed their arguments, we are not persuaded that the Company's allocated COSS requires any further modification. Therefore, the Department declines to adopt Acadia Center's and Direct Energy's recommendations.[283]

The Department has reviewed National Grid's allocated COSS and, apart from the change to the ten-percent rate cap allocation method and requiring a 200-percent of the overall rate increase cap on the increase to each rate class' distribution revenues, the Department finds that it is reasonable and consistent with Department precedent. D.P.U. 15-80/D.P.U. 15-81, at 303, 309; D.P.U. 13-90, at 240-241; D.P.U. 11-01/D.P.U. 11-02, at 434-437. Accordingly, we accept National Grid's allocated COSS as proposed and with the aforementioned changes. The Department directs the Company to rerun its allocated COSS for submission in its compliance filing to allocate its costs and expenses in excess of the ten-percent cap and 200 percent cap as

[283] In Section XI above, we address in further detail Direct Energy's arguments regarding basic service costs allocated to the Company's Basic Service Adjustment Provision.

approved in this Order. In addition, consistent with D.P.U. 15-80/D.P.U. 15-81, at 339-340, the Company shall update the class-based allocators approved in the instant case for the reconciling mechanism tariffs at the time of each tariff's next scheduled rate change.

C. Marginal Cost Study

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 11-10/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372.

2. Company Proposal

National Grid's marginal cost of service study ("MCOSS") follows the same methodology that was used in its last rate case, with minor updates (Exh. NG-HSG-1, at 3).[284] To develop the MCOSS, National Grid first identified the costs for plant additions that are

[284] The Company's MCOSS uses peak electricity use plus energy efficiency reductions as the independent variable in its regression analysis. By contrast, the MCOSS approved in D.P.U. 09-39 did not account for energy efficiency reductions (Exh. NG-HSG-1, at 13). Additionally, two un-essential variables included in the MCOSS approved in D.P.U. 09-39 were omitted from the most recent analysis due to their lack of statistical significance (Exh. NG-HSG-1, at 14). Finally, the Company updated the percentages used to allocate primary from secondary system distribution costs (Exh. NG-HSG-1, at 120).

exclusively demand-related (Exhs. NG-HSG-1, at 7; NG-HSG-2).[285] The Company then adjusted these historical costs to 2014 values using the Handy-Whitman Index (Exhs. NG-HSG-1, at 7; NG-HSG-2). Following this adjustment, National Grid multiplied total demand-related plant addition costs by the percentage of total plant addition costs associated with primary distribution service to separate plant addition costs attributable to primary versus secondary distribution systems (Exhs. NG-HSG-1, at 7; NG-HSG-2). Finally, as the MCOSS is only concerned with plant additions that are made to support load growth, the Company removed from primary and secondary distribution plant costs all plant additions made for replacement (Exhs. NG-HSG-1, at 7; NG-HSG-2; NG-HSG-3; NG-NSG-4; NG-HSG-4A).

By regressing primary distribution plant costs on electricity demand,[286] and a number of other explanatory variables, the Company determined that the marginal plant cost per kilowatt ("kW") of demand for the primary distribution sector was $495.29 (Exhs. NG-HSG-6; NG-HSG-7). Using these results,[287] the Company found that the marginal plant cost per kW of demand for the secondary distribution sector was $160.52 (Exhs. NG-HSG-6; NG-HSG-7). The Company then added general plant costs to the marginal

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285 The following variables were considered to be exclusively demand-related: (1) station equipment; (2) overhead conductors; (3) underground conductors; and (4) line transformers (Exhs. NG-HSG-1, at 7; NG-HSG-2).

286 Electricity demand is defined as system peak electricity use plus energy efficiency savings (Exh. NG-HSG-1, at 10).

287 To discern marginal plant cost in the secondary distribution system, the Company calculated the marginal plant cost for the total distribution system ($655.81), and then subtracted from it the marginal plant cost in the secondary distribution system ($495.29). The Company was not able to establish a relationship between marginal plant costs in the secondary distribution system directly because regression analysis did not lead to significant results (Exh. NG-HSG-1, at 11).

capital cost calculations in each sector and multiplied the resulting figures by the economic carrying charge rate (Exhs NG-HSG-1, at 14-15; NG-HSG-8; NG-HSG-8A).[288] The Company adjusted these amounts for O&M expenses, administrative and general expenses, and working capital (Exhs. NG-HSG-1, at 15; NG-HSG-3; NG-HSG-6; NG-HSG-9; NG-HSG-10). It then adjusted the marginal cost estimates for peak demand, 2016 price-levels, and electricity line losses (Exhs. NG-HSG-1, at 17-18; NG-HSG-10; NG-HSG-11).

National Grid calculated an annual marginal cost of $69.65 per kW of demand for the primary distribution system, and an additional $22.77 per kW of demand for the secondary distribution system (Exhs. NG-HSG-1, at 17; NG-HSG-10). After adjusting for electricity line losses, these marginal cost estimates increase to $71.15 per kW for service taken at the primary voltage level and $97.85 per kW for service taken at the secondary voltage level (Exhs. NG-HSG-1, at 17-18; NG-HSG-11).[289] Finally, the Company calculated the marginal cost for each rate class by multiplying the marginal cost per kW by the demand in the test year for each rate class, and then grossed up these amounts by the uncollectable costs for each rate class (Exhs. NG-HSG-1, at 18; NG-HSG-12).

3. Positions of the Parties

a. Attorney General

The Attorney General raises two concerns with the results of the MCOSS (Exh. AG-SJR-1, at 5-7). First, the Attorney General argues that the model used fails to take into

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288 The economic carrying charge rate is the percentage of capital cost that provides a return on rate base (Exh. NG-HSG-1, at 15).

289 Service taken at the secondary voltage level includes use of both the primary and secondary distribution system.

account important demand-related costs (Exh. AG-SJR-1, at 6). In this regard, she points specifically to the absence of structures (Account 361), poles (Account 364), and underground conduits (Account 366) in the Company's MCOSS calculation (Exhs. AG-SJR-1, at 6; AG-10-6). According to the Attorney General, including these costs would increase marginal cost by approximately 25 percent, which suggests that the current MCOSS results significantly underestimate marginal cost (Exhs. AG-SJR-1, at 6; AG-10-6).

Second, the Attorney General questions the relevance of MCOSS to the ratemaking process, particularly in designing rates (Exh. AG-SJR-1, at 6-7). In particular, she argues that marginal cost pricing does not allow companies to recover embedded costs, which would prevent companies from collecting the full price of providing its service through rates (Exh. AG-SJR-1, at 6-7). According to the Attorney General, the MCOSS is not particularly useful beyond confirming economic theory on the relationship between marginal cost and average cost (Exh. AG-SJR-1, at 6-7).

b. Company

National Grid reiterates the specifics of its MCOSS on brief (Company Brief at 200-201). The Company submits that its MCOSS is based on the same methodology that was approved in D.P.U. 09-39 (Company Brief at 201).

4. Analysis and Findings

The Department has evaluated National Grid's proposed MCOSS and finds that it incorporates sufficient detail to fully understand the methods used to determine the marginal cost estimates. Consistent with the directives in D.T.E. 05-27, at 322 & n.170, the Company

excluded from the MCOSS all production, transmission, and customer costs,[290] as they are irrelevant to the design of distribution rates under the Department's current rate design (Exh. NG-HSG-1, at 2). Further, we conclude that the Company followed all computational guidelines set forth by the Department in developing its MCOSS (Exhs. NG-HSG-1, at 9-14; NG-HSG-6; NG-HSG-7; NG-HSG-8).[291]

The Department has evaluated the Attorney General's concern regarding the Company's decision to omit certain variables, but we find that their omission is not inconsistent with Department directives. The Company's analysis is consistent with the MCOSS approved in D.P.U. 09-39. Further, while more recent MCOSS studies approved by the Department have included structures, poles, and underground conduits in their analyses,[292] we find that the nature of these accounts suggests that they might not be necessary for the purpose of the Company's MCOSS. The record shows that the Company omitted Accounts 361, 364 and 366 from the MCOSS because these plant assets have no load-carrying capacity (Exh. AG-10-6). Depending on the circumstances of the load increase, the Company may or may not be correct in this assertion. However, because the directives set forth in D.T.E. 05-27 seek to eliminate the customer component in the MCOSS, the Department finds it appropriate to treat these assets as non-load-carrying because further investment in these assets would not be required to support a

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290 Costs associated with expanding the Company's customer base.

291 These guidelines include: (1) the use of historical data sets no less than 30 years; (2) tests and remedial procedures for issues such as multicollinearity, heteroscedasticity, and autocorrelation; (3) multiple variable regression analysis; (4) consistency check against economic theory concerning marginal cost modeling; and (5) minimal dummy variable and autoregressive term use. See D.T.E. 05-27, at 317-322; D.T.E. 02-24/25, at 243-245.

292 See D.P.U. 13-90, at 241.

marginal increase in load assuming the increase is not the result of an increase in the numbers of customers. Accordingly, based on our review of the Company's MCOSS and the aforementioned considerations, the Department approves the Company's MCOSS.[293]

D. Rate Design

1. Introduction

The Company designed rates to produce a revenue requirement for distribution service of $799.1 million, and proposed to implement its rate design in two phases for Rates R-1, R-2, and G-1 (Exh. NG-PP-1, at 8-9).[294] The Company proposed its rate design with the stated goal of designing fair and equitable distribution rates across all rate classes to reflect the actual cost to serve each customer (Exh. NG-PP-1, at 23).

2. Phase I

In Phase I, the Company proposed several modifications and increases to the charges under its current rate structure (Exh. NG-PP-1, at 8). National Grid proposed a flat rate structure for Rates R-1, R-2, and G-1, and the elimination of its current inclining block rate design implemented in its last base distribution rate case (Exh. NG-PP-1, at 50, 66, 69). Further, the Company proposes to eliminate Rate S-20 (street & area lighting, Company-owned equipment, HPS conversion) and Rate E (limited residential electric space heating) (Exhs. NG-PP-1, at 22;

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293 We acknowledge the Attorney General's position regarding the relevance of the MCOSS in the context of designing rates, and we recognize that rate design is intended to recover embedded costs, which are typically higher than marginal costs. The Department's findings with respect to the Company's rate design proposals are set forth in greater detail below.

294 In Phase II, the Company has not proposed any changes to rate structure for Rates R-4, G-2, G-3, or the street lighting rate classes (Exh. NG-PP-1, at 64).

DPU-23-4). Additionally, National Grid proposes a new light emitting diode ("LED")[295] option on Rate S-1 (Company-owned street lighting rate) (Exhs. NG-PP-1, at 22; NG-PP-23, at 24, 87 (proposed M.D.P.U. Nos. 1270 (MECo) and 528 (Nantucket Electric))). For Rate G-3, the Company proposes to remove the volumetric rate and bill customers only a customer charge and demand charge (Exh. NG-PP-1, at 57-58).

Finally, for both Rates G-2 and G-3, the Company proposes to revise the definition of billing demand to include a demand ratchet (Exh. NG-PP-1, at 22, 54). Currently, a Rate G-2 or G-3 customer's billing demand is based upon the customer's maximum metered use during a 15-minute interval during all hours (Rate G-2) or peak hours (Rate G-3) of the billing month (Exh. NG-PP-1, at 56). A demand ratchet modifies the definition of a Rate G-2 or G-3 customer's billing demand to be the greater of: (1) the maximum metered kW; (2) 90 percent of the maximum metered kilovolt-amperes ("kVA"); or (3) a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months (Exh. NG-PP-1, at 56).

3. Phase II - Tiered Customer Charges

For residential and small commercial customers and industrial ("C&I") (i.e., Rates R-1, R-2, and G-1), the Company proposes to shift cost recovery from the kWh charge to tiered customer charges in Phase II of its proposal (Exh. NG-PP-1, at 8, 22). The Company's proposed Phase II rate design is to take effect no earlier than six months after the implementation of Phase I rates, or approximately May 1, 2017 (Exhs. NG-PP-1, at 8; DPU-9-16).

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295 LED lights are energy efficient, have long lives, and do not contain hazardous chemicals like the mercury that is contained in mercury-vapor lamps. See D.P.U. 11-01/D.P.U. 11-02, at 471.

National Grid's Phase II rate design proposal implements a four-tiered customer charge (Exh. NG-PP-1, at 32). The Company defines each tier by a kWh range, or a proxy for customer size, intended to represent a customer's monthly maximum demand (Exh. NG-PP-1, at 32, 36, 41). The Company proposes to assign a customer to a tier based on his or her maximum kWh usage in a billing month, over the last twelve billing months (Exh. NG-PP-1, at 36, 41). The customer charge for each succeeding tier is higher relative to the prior tier, and the tiers are intended to approximate a rate design with a customer charge and a demand charge (Exhs. NG-PP-1, at 35-36; NG-PP-Rebuttal-1, at 11). The Company proposes to recover most, if not all, of the customer-related revenue requirement and a portion of the demand-related revenue requirement based upon the billing determinants of the applicably-sized customers in each tier (Exh. NG-PP-1, at 33).

The proposed tiers and customer charges for Rates R-1 and R-2 are listed below.

	Phase II	
Tier	**kWh**	**Charge per Month**
Tier 1	0 – 250	$6.00
Tier 2	251 – 600	$9.00
Tier 3	601 – 1,200	$15.00
Tier 4	> 1,200	$20.00

(Exh. NG-PP-1, at 65).

According to the Company's billing data, approximately twelve percent of residential customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 66). Approximately 27 percent of the residential customer bills will fall into the second tier (Exh. NG-PP-1, at 66). The remaining 61 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 66). The Company proposes to recover approximately 42 percent of the Rate R-1 and R-2 revenue requirement through the four proposed customer charges,

compared to 17 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 68).

The proposed tiers and customer charges for Rate G-1 are listed below.

	Phase II	
Tier	**kWh**	**Charge per Month**
Tier 1	0 – 75	$10.00
Tier 2	75 – 500	$11.00
Tier 3	501 – 2,000	$15.00
Tier 4	> 2,000	$30.00

(Exh. NG-PP-1, at 69).

According to the Company's billing data, approximately 15 percent of G-1 customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 69). Approximately 29 percent of customer bills will fall into the second tier (Exh. NG-PP-1, at 69). The remaining 56 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 69). The Company proposed to recover approximately 31 percent of the Rate G-1 revenue requirement through the four proposed customer charges, compared to 18 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 70).

4. Attorney General's Seasonal Rate Design Proposal

The Attorney General proposes an alternative rate design for Rates R-1 and R-2 with a higher volumetric rate during July, August, and September (Exh. AG-SJR-1, at 29). She proposes a $5.50 customer charge, a base distribution rate of $0.04180 per kWh during October through June, and a base distribution rate of $0.04809 during July through September (Exhs. AG-SJR-1, at 29; AG-SJR-11). This rate design was based on the Attorney General's comparison of the summer energy use and the customer's contribution to class non-coincident peak demand, information that was provided by the Company (Exh. AG-SJR-1, at 17). The

Attorney General states that she put forth this proposal as a better proxy for demand related-costs than was instituted in either the Company's Phase I or Phase II rate design proposals (Exh. AG-SJR-1, at 18).

5. Positions of the Parties

a. Attorney General

i. Phase I

The Attorney General argues that the Company's proposed Phase I rate design is not as efficient or fair as it should be (Attorney General Brief at 130). For example, according to the Attorney General's analysis, revenues collected from a customer would only increase by 57 cents for each dollar increase in the cost of serving the customer (Attorney General Brief at 129-130, citing Exh. AG-SJR-1, at 22). Moreover, the Attorney General contends that low-use customers will experience higher bill increases (i.e., a 28.6-percent increase for consumption less than 600 kWh) than high-use customers (i.e., 11.3-percent increase for consumption greater than 600 kWh) (Attorney General Brief at 129, citing Exh. AG-SJR-1, at 12). Therefore, the Attorney General asserts that the Company's Phase I rate design would collect too much revenue from low-use customers and not enough revenues from high-use customers (Attorney General Brief at 129-130).

ii. Phase II – Tiered Customer Charges

The Attorney General argues that the Company's tiered customer charge proposal is "radically" different than any other rate design in effect in Massachusetts or elsewhere in the United States (Attorney General Brief at 131, citing Exh. DPU-12-2; Attorney General Reply Brief at 71-72). According to the Attorney General, the Company's tiered customer charge

proposal does a poor job of reflecting the cost of serving different customers and results in unfavorable bill impacts compared to alternative rate designs (Attorney General Brief at 134; Attorney General Reply Brief at 71-72, 76). Moreover, the Attorney General contends that tiered customer charges are inconsistent with the Department's rate design principles and goals (Attorney General Brief at 127). According to the Attorney General, when developing rates, the Department must balance rate design principles, giving the appropriate weight to each principle based on the importance of different policy goals (Attorney General Brief at 128). As discussed in greater detail below, the Attorney General argues that the Company's Phase II rate design proposal: (1) results in arbitrary and incorrect rate changes, violating the rate design goal of fairness; (2) results in large bill impacts, violating the rate design goal of continuity; and (3) fails to recover the appropriate costs from high-use customers, violating the rate design goal of efficiency (Attorney General Brief at 127,132). Therefore, the Attorney General asserts that the Department should reject the Company's tiered customer charge proposal (Attorney General Reply Brief at 76).

(A) Fairness

According to the Attorney General, the Company's tiered customer charge proposal violates the rate design principle of fairness (Attorney General Brief at 133). More specifically, the Attorney General asserts that customers will experience: (1) arbitrary rate changes based on the day of week when the meter is read; and (2) the potential for incorrect rate changes from estimated billing procedures (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25). As an example, the Attorney General notes that a customer may use more electricity by doing laundry and watching the television at the same time during off-peak, low demand weekend

hours, and she contends that it is unfair for a customer to be charged a higher tiered customer charge for a year based on one weekend in one billing cycle (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).[296] The Attorney General claims that the Company acknowledged this issue but did not modify its proposal (Attorney General Brief at 132, citing Exh. AG-12-9; AG-12-11). Moreover, the Attorney General assert that the Company did not address the concern that estimated meter reads could place customers into a higher tier customer charge for a year (Attorney General Brief at 133, citing Exh. AG-12-10).

(B) Continuity

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of rate continuity (Attorney General Brief at 132). Based on the Attorney General's analysis of approximately 854,000 customers on Rates R-1 and R-2, she calculated bill impacts ranging from a 14-percent decrease to a 182-percent increase (Attorney General Brief at 133, citing Exhs. AG-SRJ-1, at 27-28; AG-SJR-10; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 27-28). Therefore, the Attorney General contends that the Company's Phase II proposal results in extraordinary and unacceptable impacts on customers'

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296 The Attorney General cites to testimony from her witness to support her argument:

> Some customers use substantially more electricity on the weekends when they (and their children) are home from work or school, doing laundry, watching the television more hours per day, and heating or cooling the home to a more comfortable temperature all day. If a billing period has five Saturdays and Sundays instead of four, such a customer could be placed into a higher tier just because of the quirks of the billing cycle.

(Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).

bills (Attorney General Brief at 132; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29).

(C) Efficiency

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of efficiency (Attorney General Brief at 132). According to the Attorney General, the Company's proposal does not better reflect the cost of serving customers because a customer's bill will increase by only 54.1 cents for each dollar increase in costs (Attorney General Brief at 134, citing Exhs. AG-SJR-1, at 23; AG-SJR-8; Attorney General Reply Brief 72, citing Exh. AG-SJR-1, at 23). Moreover, she contends that the tiered customer charges fail to recover the appropriate costs from high-use customers (Attorney General Brief at 132). Therefore, the Attorney General claims that the Company has not supported its claim that tiered customer charges are more reflective of cost-based rates (Attorney General Reply Brief at 72).

Moreover, the Attorney General argues that the Company has not supported its position that the Phase II rate design proposal is a reasonable proxy for a residential rate structure, where the customer charge is designed to recover customer-related costs and a demand charge recovers capacity-related costs (Attorney General Reply Brief at 72, citing Company Brief at 217). In this regard, the Attorney General maintains that there is a weak correlation between a residential customer's annual energy consumption and its contribution to the class's non-coincident peak demand and its contribution to coincident peak demand (Attorney General Brief at 130; Attorney General Reply Brief at 72). As such, she claims that the Phase II rate design is statistically different than a rate design that includes an actual demand charge for residential customers

(Attorney General Brief at 130; Attorney General Reply Brief at 72-73). Further, according to the Attorney General's analysis of more than 12,000 residential customers with demand meters, the Company's Phase II proposal showed the worst results as a proxy demand charge rate compared to rate design alternatives (Attorney General Reply Brief at 72, citing Exh. AG-SJR-1, at 15-17). Therefore, the Attorney General asserts that the Company's tiered customer charge proposal does not meet the rate design principle of efficiency (Attorney General Brief at 129-130).

iii. Seasonal Rate Design

The Attorney General argues that her seasonal rate design proposal is consistent with the Department's rate design goals because it avoids extreme bill impacts, sends appropriate price signal, and is easy for customers to understand (Attorney General Brief at 134-135, 138). According to the Attorney General, a seasonal rate design sets cost-based rates and balances cost causation concerns with customer bill impacts (Attorney General Brief at 134-135; Attorney General Reply Brief at 72).

The Attorney General argues that with a residential customer charge of $5.50 per month and base distribution rates 15 percent higher during the months of July through September, as she recommends, the Company's residential rate design will be closer to the cost of service (Attorney General Brief at 136, citing Exh. AG-SJR-1, at 29). For example, the Attorney General asserts that her proposed seasonal rate design would recover 57.4 cents for each dollar of the cost increase, compared to National Grid's Phase I and Phase II rate design proposals, which would recover 57 cents per dollar increase and 54.1 cents per dollar increase, respectively (Attorney General Brief at 136, citing Exhs. AG-SJR-1, at 30; AG-SJR-12).

Moreover, the Attorney General argues that the 15-percent differential between summer and winter rates is less than the full difference in the cost of serving in these periods, but represents a transitional measure that takes into account customer bill impacts for all customers, including those with largely seasonal consumption (Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29). According to the Attorney General, her proposed seasonal rate design results in bill increases of 10 percent to 38 percent, compared to the Company's tiered customer charge proposal, which she claims results in bill impacts of negative 14 percent to 182 percent (Attorney General Brief at 137, citing Exh. SJR-1, at 30). Thus, the Attorney General asserts that her proposal results in bill impacts that are more reasonable than the Company's (Attorney General Reply Brief at 75, 76).

The Attorney General rejects any notion that there is no cost basis for the 15-percent differential between summer and winter base distribution rates, and she notes that the Company's own cost of service supports her recommendation (Attorney General Reply Brief at 73-74, citing Company Brief at 224). In particular, the Attorney General notes that the Company concluded from its marginal cost of service study that summer coincident peak demand was the major driver of demand-related costs on the Company's system (Attorney General Reply Brief at 74, citing Tr. 8, at 1284-1286). Moreover, the Attorney General contends that even if the Company's system peaks in the winter in a hypothetical year, the system still would be designed to serve summer peaking loads because "one of the critical factors in designing an electric distribution system is the heat associated with peak loads" and the higher ambient temperatures in the summer (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). The Attorney General reasons that the carrying capacity of distribution system equipment is

higher in the winter than in the summer because of the temperature (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). Further, the Attorney General maintains that the Company did not rebut this evidence (Attorney General Reply Brief at 74).

Additionally, the Attorney General argues that system and class peak demands are the primary drivers of demand costs in the allocated COSS (Attorney General Brief at 135). According to the Attorney General's analysis, she claims that there is a stronger correlation between peak-season energy consumption (versus annual energy use) and peak demand because of the significant relationship between a residential customer's energy consumption during the months of July through September and the contribution to system and class peak demands (Attorney General Brief at 135). For example, the Attorney General contends that 48 percent of the variation in customer's contribution to the peak demand is explained by energy consumption during July through September (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Conversely, she claims that only 27 percent of the variation in peak demand is explained by annual energy use (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Therefore, the Attorney General asserts that residential customers' consumption during July through September is a better proxy for demand than annual consumption, and, therefore, her proposed seasonal rate design serves as a better proxy for a demand-charge rate because it produces bills that are most similar to demand-based bills (Attorney General Brief at 135, citing Exh. AG-SJR-1, at 19; Attorney General Reply Brief at 73, citing Exh. AG-SJR-Rebuttal-1, at 7-8; Attorney General Reply Brief at 76). Moreover, the Attorney General claims that she and the Company agree that summer peak demands are a critically important factor in determining the cost to serve residential customers (Attorney

General Reply Brief at 74). Thus, she asserts that this fact, and her statistical analyses, prove that the seasonal rate design proposal has merit and the Department should adopt it (Attorney General Reply Brief at 75, 76).

In sum, the Attorney General argues that a seasonal rate design is consistent with the Department's rate design goals because it is fair, promotes rate continuity, is efficient, and is simple (Attorney General Brief at 137-138). The Attorney General recommends that after revenue requirement adjustments, the Department should adopt a $5.50 customer charge for Rates R-1 and R-2, and reduce the volumetric charges by an equal percentage to achieve the seasonal rate design for the residential class's share of the revenue requirement (Attorney General Brief at 138, citing Exh. AG-SJR-1, at 31; Attorney General Reply Brief at 76).

b. DOER

i. Demand Ratchets

DOER argues that the Company's demand ratchet proposal does not provide strong price signals to customers to reduce peak demand, and, therefore, violates the Department's goal of efficiency (DOER Brief at 5, citing D.P.U. 09-39, at 401; DOER Reply Brief at 3, citing D.P.U. 09-39, at 401). DOER contends that under the Company's proposal if a customer reaches a new monthly peak demand in a twelve month period, a demand ratchet increases the customer's demand charge immediately (DOER Brief at 4). DOER claims, however, that a customer would have to maintain a lower level demand for a year before that customer sees a lower demand charge because the charge is only reduced after a customer maintains lower peak monthly demand for eleven consecutive months (DOER Brief at 4-5). DOER argues that the eleven month lag in savings from a lower level demand reduces a customer's incentive to invest

in technology that reduces peak demand, making those projects harder to justify because of the longer payback period for capital expenditure (DOER Brief at 5; DOER Reply Brief at 2-3). DOER maintains that it is common industry practice to justify capital investments for commercial customers with short payback periods (DOER Brief at 3). According to DOER, a project is considered more risky if the payback period is longer than one to three years (DOER Brief at 3).

Further, DOER argues that National Grid's analysis purporting to show that a hypothetical customer's energy efficiency savings is minimally impacted by the Company's proposed demand ratchet shows an incomplete picture (DOER Reply Brief at 1-2, citing Company Brief at 227-228; Exh. DPU-15-16). DOER contends that the Company's example uses a customer with a very flat load profile implementing energy efficiency measures (DOER Reply Brief at 1). DOER claims that the Company's example fails to consider the impacts on customers with a load that varies significantly month-to-month (i.e., customers that are more likely to implement peak demand reduction measures) (DOER Reply Brief at 2, citing Exh. DPU-15-16).

In this regard, DOER demonstrates the impact of the demand ratchet on a hypothetical customer with a high peak load implementing a project to reduce peak demand (kW), as opposed to an energy efficiency project reducing kWhs (DOER Reply Brief at 2). According to DOER, a Rate G-3 customer installing a solar plus storage project could reduce its summer peak demand from 400 kW to 250 kW and non-peak demand from 350 kW to 200 kW (DOER Reply Brief at 2). Further, DOER claims that this hypothetical customer expects an immediate reduction to its demand charge based on the new peak demand of 250 kW (DOER Reply Brief at 2). DOER

asserts, however, that with a demand ratchet, the customer only sees a reduction to 300 kW (or 75 percent of the existing 400 kW summer peak demand) (DOER Reply Brief at 2). DOER notes that it is not until the investment has been in place for eleven months that the demand charges are assessed at the new demand and the full benefit of the demand reduction project is realized (DOER Reply Brief at 3). Thus, DOER asserts that because of the eleven month lag, a demand ratchet will increase the probability that a customer with a load that varies significantly month-to-month will not invest in demand reduction technologies (DOER Brief at 5; DOER Reply Brief at 2-3).

Finally, DOER argues that the high peak load to total load ratio customers are the exact type of Rate G-2 or Rate G-3 customers that should be incentivized to reduce their peak load, but are the most negatively impacted customers by the proposed demand ratchet (DOER Reply Brief at 3). Thus, DOER recommends that the Department direct the Company in its compliance filing to re-file Rate G-2 and Rate G-3 tariffs without demand ratchets, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 5; DOER Reply Brief at 3).

ii. Tiered Customer Charges

DOER does not object to the Company's proposed Phase I customer charge proposal, but opposes its Phase II rate design proposal for Rates R-1, R-2, and G-1 (DOER Brief at 6). DOER argues that the Department should reject the tiered customer charge proposal because it: (1) delays the benefits of, and thereby discourages customer investment in, energy savings measures; (2) disproportionately affects lower usage customers; and (3) does not serve as an appropriate proxy for a demand charge (DOER Brief at 7-8). Further, as described in more detail below, DOER contends that the Company did not demonstrate that its Phase II rate design

proposal is consistent with the Department's rate structure goals and objectives (DOER Reply Brief at 4). DOER recommends that the Department reject the Company's Phase II proposal and direct the Company in its compliance filing to revise its tariffs to reflect a flat rate structure, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 6; DOER Reply Brief at 4).

Further, DOER argues that under the Company's Phase II rate design proposal, a customer will pay a higher customer charge based on the previous summer's usage even if the customer installs energy efficiency investments (e.g., efficient heating and cooling) to save money in the upcoming summer (DOER Brief at 7). According to DOER, a delay in savings discourages investment and affects the Commonwealth's goal to reduce energy costs (DOER Brief at 7). Moreover, DOER maintains that the Company did not analyze its Phase II rate design impacts on customer incentives to reduce consumption, including achievement of the Company's three-year energy efficiency plan (DOER Brief at 7, citing DOER 2-18(c); Tr. 5, at 634. Tr. 11, at 1-5, 16-20). Therefore, DOER asserts that the Company's tiered customer charge proposal should not be approved because it risks undermining the Commonwealth's energy policy goal of maximum deployment of energy efficiency (DOER Brief at 7).

(A) Fairness/Continuity

Regarding the rate design goals of fairness and continuity, DOER argues that low-use customers will incur higher bill impacts under the tiered customer charge proposal (e.g., a Rate R-2, low-use customer using 610 kWh per month will experience a 25 percent bill increase while a Rate R-2, high-use customer using 1,000-1,250 kWh per month will experience a 14 to 16 percent bill increase) (DOER Brief at 7-8, citing Exh. LI-JH-1, at 14). DOER expresses

concern with these bill impacts because it claims that low-income customers tend to be low-use customers (DOER Brief at 8). Therefore, DOER recommends that the Department reject the Company's tiered customer charge proposal because it disproportionately (and negatively) affects lower and moderate income customers, thereby violating the Department's rate design goal of fairness (DOER Brief at 8).

(B) Efficiency

DOER rejects any notion that a customer's maximum monthly energy use in a year is a proxy for their demand (DOER Brief at 8, citing Tr. 5, at 635). According to DOER, a rate structure based on maximum demand should consist of a customer charge and a per-kW charge based on maximum kW demand (DOER Brief at 8; DOER Reply Brief at 4). Because the Company's tiered customer charges are not based on kW demand or the customer's maximum demand in a month, DOER maintains that the Phase II rate design proposal does not represent a true demand charge (DOER Reply Brief at 4). Further, DOER argues that the Company's tiered customer charge proposal uses a kWh charge as a proxy for demand, and therefore fails to consider a customer's coincident peak demand (DOER Brief at 8; DOER Reply Brief at 4). Accordingly, DOER maintains that the Company's tiered customer charges are not an appropriate and efficient proxy for demand charges (DOER Brief at 8; DOER Reply Brief at 3).

Moreover, because the Company's proposal is based on total kWh usage in a month, DOER argues that a customer does not receive the proper price signal, which a demand charge would provide, to adjust his or her energy consumption within a month (DOER Brief at 8; DOER Reply Brief at 4). For example, DOER contends that under the Company's tiered customer charge proposal, a customer charging an electric vehicle, doing laundry, and using an

air conditioner at the same time would be billed the same amount as a customer staggering those activities throughout a month (DOER Brief at 8; DOER Reply Brief at 4). DOER maintains, however, that under a rate design with a true demand charge, the customer's bill would be lower under the staggered activity scenario (DOER Brief at 8; DOER Reply Brief at 4). Thus, for all of these reasons, DOER asserts that the Company's Phase II rate design is contrary to the Commonwealth's energy efficiency goals because it does not provide a price signal to reduce peak demand and lower system wide energy costs (DOER Reply Brief at 4).

c. Low Income Network

i. Phase I

The Low Income Network argue that the Department should reject the customer charge increases proposed by the Company in Phase I for low-income customers taking service on Rate R-2 (Low Income Network Brief at 13).[297] According to the Low Income Network, the Company's proposal to shift revenue collection from the volumetric rates to the customer charges burdens low-use customers that are disproportionately low-income (Low Income Network Brief at 13). The Low Income Network calculates the bill impacts for Rate R-2 customers that range from a 15.9-percent increase in Phase I to up to a 60-percent increase in Phase II (Low Income Network Brief at 14-15, citing Exhs. LI-JH-1, at 14; AG-SJR-1, at 28). Moreover, the Low Income Network argues that the Company's proposed increases to customer charges diverge from the Commonwealth's policies and programs designed to promote energy efficiency and investments in renewable energy and DG (Low Income Network Brief at 13-14).

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297 While the Low Income Network's arguments are focused on low income customers and, therefore, on Rate R-2, many of the low-income customers take service on Rate R-1 (Low Income Network Brief at 13, n.39).

Therefore, the Low Income Network asserts that Rate R-2 customers will not be able to reduce the cost on their bills by reducing consumption under the Company's proposal (Low Income Network Brief at 14).

Further, the Low Income Network argues that a review of rate design proposals should take into account the differences between low income households and higher-income customers (Low Income Network Brief at 14). According to the Low Income Network, low income households generally have lower electric use than higher-income customers (Low Income Network Brief at 14). For example, the Low Income Network asserts that low-income customers on Rate R-2 have median monthly usage of approximately 460 kWh compared to the median usage for Rate R-1 customers of approximately 500 kWh per month (Low Income Network Brief at 14, citing Exhs. LI-JH-1, at 14; LI-2-10, Atts. 1 & 2).

ii. Tiered Customer Charges

The Low Income Network argues that the Department should also reject the Company's tiered customer charge proposal for Rate R-2 customers (Low Income Network Brief at 13). The Low Income Network maintains that the Company's proposed Phase II rate design will not achieve the rate design goals set forth by National Grid of ensuring that DG customers make a "modestly" greater contribution to Company distribution costs (Low Income Network Reply Brief at 3).

Further, the Low Income Network argues that the Phase II rate design proposal runs counter to the Commonwealth's energy efficiency and renewable energy goals (Low Income Network Brief at 15-16, citing Green Communities Act, Acts of 2008, c. 169; Global Warming Solutions Act, Acts of 2008, c. 298; An Act Relative to Solar Energy, Acts of 2016, c. 75; Low

Income Network Reply Brief at 3). The Low Income Network maintains that some of these energy efficiency policies date back to regulatory policies the Department established in the 1980s (Low Income Network Brief at 17, citing Order Opening Investigation, D.P.U. 11-120, at 1-2 (2011)). According to the Low Income Network, increasing customer charges and reducing volumetric charges reduces the incentive to implement energy efficiency measures because the value of each kWh saved is thereby reduced (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 14-15; Low Income Network Reply Brief at 4). Further, the Low Income Network claims that the customer charge tiers create a further barrier to energy efficiency because customers cannot lower their bills for up to twelve months (Low Income Network Brief at 16, citing Tr. 5, at 633-634; Low Income Network Reply Brief at 4). In addition, the Low Income Network maintains that the Company did not perform analysis of the impact of its Phase II rate design proposal on the adoption of energy efficiency measures or renewable energy technology (Low Income Network Brief at 16, citing Tr. 5 at 633-634).

According to the Low Income Network, the Company's tiered customer charge proposal creates barriers for low-income customers that conserve electricity to maintain low electricity costs (Low Income Network Brief at 15). The Low Income Network argues that the Company's tiered customer charge proposal increases the burdens on low income customers who tend to be low-use customers, which the Low Income Network maintains is contrary to the Department's fairness and continuity rate design goals (Low Income Network Reply Brief at 3, 4). Additionally, the Low Income Network contends that by definition, a low-use customer is less likely to contribute to peak demand than a high-use customer (Low Income Network Reply Brief at 4). The Low Income Network maintains that customer charges are assessed equally to all

customers without considering monthly use, and therefore, customer charges affect customers with the lower use more than they affect customers with higher use (Low Income Network Reply Brief at 4). Under the Company's proposal, the Low Income Network claims that the median Rate R-2 customer would incur a bill increase of 25 percent and some customers would incur increases of more than 60 percent (Low Income Network Reply Brief at 4-5).

Further, the Low Income Network argues that the Company's tiered customer charge proposal may be confusing to customers (Low Income Network Brief at 16). According to the Low Income Network, customers will not understand their bills or how to control their use if volumetric charges are reduced, customer charges vary annually with use, and customers are unable to monitor their use in real time (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 15; Tr. 8, at 1308; Low Income Network Reply Brief at 4).

Additionally, the Low Income Network maintains that National Grid's proposed Phase II rate design is an inadequate proxy for demand, and, therefore, will not achieve the rate design goals set forth by the Company (Low Income Network Brief at 15, citing Exh. AG-SJR-1, at 16-17; Low Income Network Reply Brief at 3). According to the Low Income Network, the Company fails to prove that distribution costs are driven by maximum monthly energy use as a reflection of demand (Low Income Network Reply Brief at 3). As a result, the Low Income Network asserts that customers can be bumped into a higher tier that does not accurately correlate with the peak demands that drive system costs (Low Income Network Brief at 15). Moreover, the Low Income Network argues that the correlation between historical energy consumption and demand is weak and does not consider whether a customer's maximum historical demand occurred at a time coincident with local or system peaks (Low Income

Network Reply Brief at 3). Instead, the Low Income Network contends that the costs of meeting demand are driven by local and system peaks (Low Income Network Reply Brief at 3, citing DOER Brief at 8; Attorney General Brief at 130, 134; NECEC Brief at 2, 11).

iii. Conclusion

In sum, the Low Income Network argues that Massachusetts law supports minimizing the risk that low-income utility consumers will lose their utility service (Low Income Network Brief at 17, citing G.L. c. 164, § 1F(4)). Further, the Low Income Network contends that the Commonwealth has policies promoting energy efficiency and renewable energy (Low Income Network Brief at 17). In addition, the Low Income Network claims that National Grid's need for rate design reform does not outweigh customers' needs for rate continuity, low-income customers' need for affordability, and policy requirements for energy efficiency and equity, especially in light of the revenue stability provided through revenue decoupling and other risks compensated through the Company's rate of return (Low Income Network Reply Brief at 5). Accordingly, the Low Income Network recommends that the Department reject the Company proposals of raising customer charges and lowering volumetric energy charges because these proposals will undermine the Commonwealth's ability to achieve its energy goals (Low Income Network Brief at 17).

d. Limited Intervenors[298]

i. Demand Ratchet

EFCA argues that the Company did not properly support its demand ratchet proposal for Rates G-2 and G-3 (EFCA Brief at 17, 18-19; EFCA Reply Brief at 15-16).[299] According to

[298] For purposes of this section, the "Limited Intervenors" shall refer to Acadia Center, EFCA, NECEC, and Vote Solar, collectively.

EFCA, the Company did not analyze the basis of the demand ratchet's structure or its impact on current customers to support its proposal (EFCA Brief at 17, 18; EFCA Reply Brief at 16, citing Tr. 7, at 1,108). Moreover, EFCA contends that the only evidence that the Company provided to support its proposal was that a utility in Rhode Island implemented a demand ratchet in 1987 (EFCA Brief at 18; EFCA Reply Brief at 15). However, EFCA claims that the Company did not analyze the similarities and differences between Massachusetts and Rhode Island or the changing conditions over the last 30 years (EFCA Reply Brief at 15-16). EFCA asserts that demand ratchets are an obsolete rate design tool, and National Grid's "back-of-the-envelope" bill impact estimation is inadequate evidence to support the Company's proposed demand ratchet rate design (EFCA Reply Brief at 16, citing Exh. DPU-AC-1-3, Att. 1).

Moreover, EFCA argues that a demand ratchet conflicts with the Department's rate design goals and the concept of efficient price signals for use of resources (EFCA Brief at 6, 11-12; EFCA Reply Brief at 10, citing Exh. EFCA-TM/MW-1, at 8; Boston Gas Co. v. Department of Public Utilities, 405 Mass. 115, 116, (1989)). EFCA contends that, because a demand ratchet reduces the volumetric price signal, it reduces the incentive for customers to manage their use and, as such, may result in higher total energy consumption (EFCA Brief at 5-6, 11-12). Further, EFCA claims that a demand ratchet operates as a fixed charge because it

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299 On September 9, 2016, EFCA filed with the Department a copy of the 2016 NARUC Draft Manual on Distributed Energy Resources Compensation, along with a cover letter and comments regarding the draft manual. In the cover letter, EFCA 'encouraged' the Department to consider certain aspects of the draft manual as we evaluate National Grid's proposed rate increase and design. On September 16, 2016, the Company filed a response to EFCA's filing. EFCA's filing was made well after the record closed, with no opportunity for inquiry. Further, the filing is related to a draft manual that apparently has not yet been adopted by NARUC. The filing constitutes extra-record evidence, to which the Department gives no probative weight. Further, we decline to take official notice of the draft manual pursuant to 220 C.M.R. § 1.10(2).

provides little incentive for a customer to reduce demand each month after the annual peak is set (EFCA Brief at 6, 13, 19). According to EFCA, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" (EFCA Brief at 13, citing Exh. EFCA-TW/MW-1, at 38; EFCA Brief at 19). Therefore, EFCA claims that a "fixed" demand charge does not account for the timing of a customer's demand, and its coincidence with the system peek, and also fails to reflect cost causation (EFCA Brief at 21).

Further, EFCA argues that demand ratchets discourage the adoption of new technologies (e.g., storage and DG), and EFCA notes that a customer with these technologies could face a 21 percent bill increase (EFCA Brief at 5-6; EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Moreover, EFCA contends that a customer with solar DG will incur a demand charge based on higher winter demand because there are more daylight hours in the summer than there are in the winter (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Thus, EFCA claims that the demand ratchet proposal does not recognize that these customers have low demand in the summer when the distribution system is most stressed (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). EFCA also asserts that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages without recognizing that these customers could reduce system costs for all customers (EFCA Brief at 20-21, citing Exh. EFCA-TW/MW-1 at 52).

EFCA also rejects the notion that there will be a "de minimis" impact of the demand ratchet on the first year of an investment, and EFCA argues that the Company's purported analysis showing the same is limited and does not prove that technology investment will not be "deleteriously" impacted (EFCA Reply Brief at 13-15, citing Company Brief at 227-228;

Exh. DPU-15-16). Instead, EFCA claims that its own analysis show a range of bill impacts, such as bill increases of: 2.6 percent (i.e., similar to the Company's analysis), five percent, and 21 percent (EFCA Reply Brief at 15, citing Exh. EFCA-TW/MW-1, at 50).

According to EFCA, the Company has not carried its burden of proof to warrant approval of the demand ratchet (EFCA Reply Brief at 12). Accordingly, EFCA recommends that the Department reject the Company's demand ratchet proposal (EFCA Brief at 6, 13, 21).

ii. Tiered Customer Charges

(A) Introduction

The Limited Intervenors argue that the Department should reject the Company's tiered customer charge proposal (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 1; Vote Solar Brief at 7). According to the Limited Intervenors, the Company's proposed Phase II rate design does not meet one or more of the Department's rate design goals (i.e., fairness, continuity, simplicity or understandability, efficiency or cost causation) (Acadia Center Brief at 2, 12; EFCA Brief at 3, 15; NECEC Brief at 1, 9; NECEC Reply Brief at 1; Vote Solar Brief at 7).

Further, the Limited Intervenors argue that the Company did not provide evidence of a cost shift from DG customers to non-DG customers or further analysis to support its Phase II rate design proposal (Acadia Center Brief at 2, 10; Acadia Center Reply Brief at 3; EFCA Brief at 9, citing Exh. NG-PP-1, at 28; EFCA Reply Brief at 4; Vote Solar Brief at 7, 8, citing Exhs. NG-PP-1, at 28; NG-PP-Rebuttal-1, at 53; Tr. 5, at 616-617; NECEC Brief at 45-46; NECEC Reply Brief at 1-2, 8-9). Specifically, the Limited Intervenors argue that the Company did not properly analyze the costs or benefits attributable to DG customers in its service territory

(Acadia Center Brief at 12; Acadia Center Reply Brief at 3; EFCA Brief at 9-10, citing Exhs. EFCA-TW/MW-1, at 19, 34, 36; EFCA-TW/MW-Rebuttal-1, at 5 n.9; EFCA-1-11; Tr. 7, at 1,067, 1,070-1,071; EFCA Reply Brief at 4-8; NECEC Brief at 46, citing Exh. LI-1-10; Tr. 5, at 602; Vote Solar Brief at 8, citing Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; Tr. 5, at 620; Vote Solar Reply Brief at 4). According to the Limited Intervenors, without quantifying the costs and benefits attributable to DG customers, the Company cannot demonstrate that a cost-shift occurs (Acadia Center Brief at 10-12; EFCA Brief at 10; NECEC Brief at 45-46, citing Exh. EFCA-TM/MW-1, at 21-22; Vote Solar Reply Brief at 3-4). Thus, the Limited Intervenors claim that because the Company has not proven a cost shift with any analysis, its proposed Phase II rate design is not even necessary (Acadia Center Brief at 12; EFCA Brief at 10-11; EFCA Reply Brief at 4; NECEC Reply Brief at 8-10; Vote Solar Brief at 9; Vote Solar Reply Brief at 3-5). Further, EFCA and NECEC argue that National Grid did not analyze the effects of the tiered customer charges on the Company's alleged cost shift (EFCA Brief at 12, citing Exh. EFCA-1-2; NECEC Reply Brief at 8-9).

NECEC and Vote Solar also argue that the Company has not met its burden with analysis to show that its "ideal rate design," which includes actual residential demand charges, is just and reasonable, in the public interest, and desirable (NECEC Brief at 10-11; NECEC Reply Brief at 2; Vote Solar Reply Brief at 2-3, citing Fitchburg Gas Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 582 (1978)). For example, Vote Solar contends that the Company did not provide evidence showing that actual demand charges will change residential and small C&I behavior or that these customers understand demand charges and have the tools to manage peak demand (Vote Solar Reply Brief at 3, citing Exh. VS-NP-1, at 39-40). Further,

NECEC claims that the Company's Phase II rate design does not meet its intent of moving toward demand charges, and Vote Solar argues that no other state-regulated utility in the country requires mandatory demand charges for residential customers (NECEC Brief at 9; Vote Solar Brief at 1). Finally, NECEC and Vote Solar assert that no other utility has implemented a rate design similar to the Company's proposal (NECEC Brief at 45, citing Exh. NECEC-RTB-1, at 14, 35; Tr. 5, at 654-657; Vote Solar Reply Brief at 1, citing Exh. DPU-12-2, Tr. 5, at 638-641).

(B) G.L. c. 164 § 141[300]

EFCA, NECEC, and Vote Solar claim that the Company's proposed Phase II rate design runs counter to state policy to promote energy efficiency and DG and may result in higher electricity prices for all electric customers in the Commonwealth (EFCA Brief at 2, 4; NECEC Reply Brief at 12-13; Vote Solar Brief at 1, 22). In particular, Vote Solar notes that the relevant portion of G.L. c. 164 § 141 ("§ 141) provides: "[i]n all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation" (Vote Solar Brief at 22, citing § 141).

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300 G.L. c. 164, § 141 provides:

> In all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

In Section XIII.E below, we address § 141 as it relates to the impact of on-site generation on affordability of electric service for low income customers, as provided by the second clause of § 141.

According to Vote Solar, the Company did not provide evidence regarding the impact of its tiered customer charges on energy efficiency, compliance with the three-year energy efficiency plan, and incentives to lower demand (Vote Solar Brief at 22-23, citing Exh. DOER-2-18; Tr. 5, at 634; Vote Solar Reply Brief at 11-12). Vote Solar argues that customers are incentivized to implement energy efficiency by the opportunity to save money through lowering their total kWh charges (Vote Solar Brief at 22, citing Exh. DOER-2-16; Tr. 5, at 632; Acadia Center Reply Brief at 7). However, Vote Solar maintains that the purpose of National Grid's tiered customer charges are "to ensure that customers who reduce kWh consumption either through implementation of DG or energy efficiency will pay their fair share of the Company's distribution system," shifting cost recovery away from the kWh charges and causing kWh rates to decline (Vote Solar Brief at 22, citing Exh. NG-PP-1, at 32, 64; Tr. 5, at 750). Vote Solar maintains that the Company does not dispute this evidence (Vote Solar Reply Brief at 11).

Acadia Center challenges the Company's analysis that purportedly shows that tiered customer charges have no effect on energy efficiency, and argues that such analysis is "cherry-picked" and misleading (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). In particular, Acadia Center contends that the Company's analysis shows a Tier 3 customer using 650 kWh per month reducing consumption by 23 percent after installing energy efficiency technology, causing the customer to drop to Tier 2 with a new baseline of 500 kWh (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). However, Acadia Center claims that under the same scenario, with a Tier 3 customer using 800 kWh per month, the customer would not

drop to Tier 2 after the 23-percent reduction in consumption (Acacia Center Reply Brief at 7, n.27, citing Exh. LI-1-14, Att.).

Further, Vote Solar argues that it is not advocating for "an absolute ban on any rate design that would affect existing incentives for customers to pursue DG and energy efficiency" (Vote Solar Reply Brief at 12, citing Company Brief at 222). Instead, Vote Solar maintains that the Company did not provide the evidence to satisfy its statutory obligation in the instant proceeding (Vote Solar Brief at 22-23, citing § 141; Vote Solar Reply Brief at 12-13).

Moreover, NECEC and Vote Solar argue that § 141 does not require the Department to consider the impacts of the Company's proposed rate design along with the incentives that are provided to energy efficiency and on-site generation (Vote Solar Reply Brief at 12-13, citing Company Brief at 222 (emphasis in original); NECEC Reply Brief at 12-13, citing Company Brief at 222). Rather, NECEC asserts that the Department must be mindful of the effects of rate design on the development of energy efficiency and on-site generation (NECEC Reply Brief at 13).

(C) Continuity and Fairness

Some of the Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's continuity goal and does not improve customer equity (Acadia Center Brief at 2, 12-13; Acadia Center Reply Brief at 5; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 27; NECEC Reply Brief at 11). In particular, NECEC contends that the Phase II rate design proposal is based on arbitrary factors that drive significant changes in customers' distribution bills (NECEC Brief at 9). Further, EFCA and NECEC calculate that under the Company's proposal the residential customer charge will increase by up to 400 percent

and the small commercial customer charge will increase by up to 200 percent (EFCA Brief at 16; NECEC Brief *at* 27, citing Exh. EFCA-TM/MW-1, at 7, 40). In addition, according to Acadia Center and NECEC, residential annual distribution bill impacts will range from approximate decreases of 10 percent to increases of over 100 percent (Acadia Center Brief at 13, citing Exh. AG-SJR-1, at 26-28; NECEC Brief at 28, citing Exhs. AG-SJR-1, at 24, 27-28; AG-SJR-10). More specifically, NECEC notes that ten percent of R-1 customers will incur bill increases of 45 percent or more, and 1,000 R-2 customers will incur bill increases of 60 percent or more (NECEC Brief at 28, citing Exhs. AG-SJR-1, at 27-28; AG-SJR-10; NECEC Reply Brief at 11-12). Further, NECEC claims that customers will be subjected to two significant changes in rate structure within a short period of time; first, the Company's Phase II proposal, then time-varying rates pursuant to the Department's decision in Time Varying Rates, D.P.U. 14-04-C (2014) (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42). NECEC asserts that these two consecutive rate changes violate the Department's rate design goal of continuity (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42).

Acadia Center argues that the proposed Phase II rate design is not fair because it shifts cost burden from high-use customers to low-use customers, and low-use customers are disproportionately low-income customers (Acadia Center Brief at 12-13, citing Exh. DPU-AC-1-2, Att.; Acadia Center Reply Brief at 5). For example, Acadia Center calculated only a $5 bill increase for a customer using 2,000 kWh per month, but a $10 monthly bill increase for a customer using 600 kWh per month (Acadia Center Brief at 13, citing Exhs. AC-1-8, Att.; NG-AC-1-1, Att. 1 at 1). Further, Acadia Center contends that approximately 25 percent of customers with usage above the highest tiered customer charge

cutoff would pay a per-kWh rate that is lower than their current tail block per-kWh rate (Acadia Center Brief at 13; Acadia Center Reply Brief at 5-6).

Further, Vote Solar maintains that the Company's Phase II rate design proposal is a punitive, one-sided ratchet, proposed without any supporting analysis to determine how likely customers are to move to different tiers (Vote Solar Brief at 18-19, citing Tr. 5, at 631). According to Vote Solar, using twelve months of historical use information to identify maximum monthly use is unreliable because the Company did not study whether the maximum monthly use for a customer is consistent year to year (Vote Solar Brief at 17, citing Exh. NG-PP-Rebuttal-1, at 29; Tr. 5, at 728-729; RR-NECEC-1, Att.; Vote Solar Reply Brief at 8-9). Moreover, NECEC contends that similar customers could have nearly identical patterns of use (e.g., customer one uses 600 kWh in a billing period while customer two uses 599 kWh), but a customer on Tier 3 for distribution services is billed 33 percent more than a customer on Tier 2 (NECEC Brief at 22, citing Exh. EFCA-TW/MW-1, at 33; NECEC Reply Brief at 12). Therefore, NECEC argues that this divergence of bills is unfair and does not reflect cost of service differences (NECEC Brief at 22-23).

(D) Simplicity

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's simplicity goal (Acadia Center Brief at 2, 14; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 23, citing D.T.E./D.P.U. 06-82-A, at 75; NECEC Reply Brief at 10; Vote Solar Brief at 15-16; Vote Solar Reply Brief at 8-9). Further, Acadia Center contends that the Company's Phase II rate design proposal is a departure from traditional rate

design and should have included bill management tools because potential bill impacts are large (Acadia Center Reply Brief at 6).

The Limited Intervenors also argue that customers cannot easily monitor, respond to, and manage bills under the Company's proposed Phase II rate design, and NECEC alleges that customers would find the adjustment to a tiered customer charge difficult (Acadia Center Brief at 14; Acadia Center Reply Brief at 6; EFCA Brief at 15, citing Exh. LI-2-12; NECEC Brief at 23-25, 27, citing Exhs. EFCA-TW/MW-1, at 41; NECEC-RTB-Rebuttal-1, at 16; Vote Solar Reply Brief at 8). Further, NECEC and Vote Solar contend that customers will not know when they are close to a tier boundary because they are unable to monitor use in real time (NECEC Brief at 25, citing Exh. LI-2-12; Tr. 5, at 626-627; Vote Solar Brief at 16; Vote Solar Reply Brief at 8). Additionally, Acadia Center and NECEC claim that customers will not understand what kinds of behavior will move them to a higher tier or whether energy efficiency and conservation measures will drop them into a lower tier (Acadia Center Brief at 14; NECEC Brief at 24-25). Accordingly, NECEC asserts that an arbitrary event could set a customer's new maximum annual kWh and move the customer into a higher tier (NECEC Brief at 25).

NECEC also argues that the Company's proposed Phase II rate design is complex and leaves other arbitrary consequences in place, such as the length of a billing period, number of weekend days within a billing period, and estimated meter reads, that could affect a customer's maximum monthly use and customer charge tier for an entire year (NECEC Brief at 22, citing Exhs. AG-SJR-1, at 24-26; NG-PP-Rebuttal-1, at 63; AG-SJR-Rebuttal-1, at 16; NECEC Reply Brief at 12). Further, Vote Solar contends that a customer may take action to lower his or her maximum monthly use, but it may not result in a bill reduction (Vote Solar Brief at 17-18,

citing Tr. 5, at 629; Vote Solar Reply Brief at 9). NECEC and Vote Solar maintain that it is unfair to subject customers to a higher tiered customer charge for twelve months based on one month's use, but to be moved to a lower tier, the customer must wait until he or she sustains a reduction in maximum use for twelve months (NECEC Brief at 22; Vote Solar Brief at 18-19, citing Tr. 5, at 630-631; Vote Solar Reply Brief at 8). EFCA describes the tiered customer charge proposal as having the same effect as the demand ratchet proposal for Rates G-2 and G-3 (EFCA Reply Brief at 9-10, citing Exh. EFCA-TW/MW-1, at 11).

Vote Solar also rejects the notion that customers are able to respond to demand charges, and, therefore, the Company's tiered customer charge proposal is acceptable, as Vote Solar argues that the Company's position is based on its experiences with larger commercial customers, not residential customers (Vote Solar Brief at 15-16, citing Tr. 5, at 675-676). Further, NECEC contends that residential and small commercial customers will not understand demand, much less the relationship between demand and their monthly use (NECEC Brief at 24, citing Exhs. VS-NP-Rebuttal-1, at 18; EFCA-TM/MW-1, at 41).

Moreover, NECEC and Vote Solar argue that there is no evidence in National Grid's Smart Energy Solutions Program, which studied customer behavior under time-of-use/critical peak pricing and peak-time rebate programs, that supports the Company's position that customers would understand the tiered customer charge proposal (Vote Solar Brief at 16, citing Tr. 5, at 624-626; NECEC Brief at 23-24, citing Exh. NECEC-RTB-Rebuttal-1, at 15; Tr. 5, at 625; NECEC Reply Brief at 10, citing Tr. 5, at 625-626). Further, although the Company plans to implement an outreach and education program for its tiered customer charges, NECEC and Vote Solar contend that the Company did not develop the materials and present this

evidence (NECEC Reply Brief at 11; Vote Solar Brief at 17, citing Exh. VS-2-6; Vote Solar Reply Brief at 9).

Finally, in response to the Company's argument that time-varying rates are complicated, Acadia Center and NECEC maintain that customers are able to respond to time-varying prices for other products, such as travel and cell phones (Acadia Center Reply Brief at 6; NECEC Reply Brief at 10). Acadia Center asserts that as technology advances, more complicated rate designs become more feasible (Acadia Center Reply Brief at 5-6).

(E) Efficiency

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's rate design goal of efficiency because it does not send transparent price signals, it is not based on cost-causation principles, it is not an improvement from current rate design, and it is unjustified (Acadia Center Brief at 2, 14, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 3; EFCA Reply Brief at 11; NECEC Brief at 14, 16-17, 23; Vote Solar Brief at 9-10, 12 n.8, 15). Therefore, the Limited Intervenors claim that the Company's tiered customer charge proposal fails to represent an efficient, cost-based rate design (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 7-9; EFCA Reply Brief at 11; NECEC Reply Brief at 2-3; Vote Solar Brief at 15).

Further, EFCA contends that the Company has conflated historical and future costs in designing its tiered customer charges (EFCA Brief at 14). In this regard, EFCA notes that historical costs are fixed, sunk costs, but the purpose of rate design is to not only recover historical costs, but also to send clear price signals in order to encourage the efficient use of the distribution system and reduce avoidable future costs (EFCA Brief at 14). EFCA contends that

the volumetric rate sends a price signal to customers that reduced system use results in reduced costs (EFCA Brief at 14). Further, EFCA maintains that this price signal will reduce the need for supply-side resources, and, therefore, reduce long-run electricity costs for all customers (EFCA Brief at 15). Thus, EFCA and Vote Solar assert that the tiered customer charge proposal does not "provide strong signals to customers to decrease excess energy consumption in consideration of price and non-price social, resource, and environmental factors" because customers will be locked into a tier for a year (EFCA Brief at 4, 15; Vote Solar Reply Brief at 8-9). Accordingly, EFCA and Vote Solar maintain that such results are contrary to the Department's goal of achieving efficient price signals and efficiency in customer consumption decisions (EFCA Brief at 15; Vote Solar Reply Brief at 8-9).

Moreover, the Limited Intervenors disagree with the Company's portrayal of the relationship between a customer's maximum monthly kWh use and maximum hourly kW demand (Acadia Center Brief at 14-15; EFCA Brief at 15; NECEC Brief at 17; NECEC Reply Brief at 3-4; Vote Solar Brief at 9-10). According to NECEC and Vote Solar, the low R-squared[301] values produced from the Company's analysis demonstrate a weak relationship between maximum billed use and maximum hourly load for each customer charge tier, and therefore, maximum annual kWh serves as poor proxy for a customer's contribution to non-coincident peak demand (NECEC Brief at 16-18, citing Exh. VS-NP-1, at 26; Vote Solar Brief at 10-12, citing Exh. AG-SJR-5; DPU-9-8; Tr. 5 at 637-638, 688-689; Vote Solar Reply Brief at 6, citing Exh. DPU-9-8, Att.). Further, EFCA, NECEC, and Vote Solar argue that a

[301] The R-squared analysis measures the strength of a relationship (Exh. DPU-15-9; Tr. 8, at 1218). A R-squared value of one means that the model explains all the variability of the data, and a R-squared value of zero means that the model explains none of the variability of the data (Tr. 5, at 636).

customer's highest month of use is a worse indicator of the customer's maximum demand than a customer's average energy use (i.e., current rates) (EFCA Brief at 15; EFCA Reply Brief at 11, citing Exh. EFCA-TW/MW-1, at 25-28; NECEC Brief at 17-18, citing Exhs. NECEC-RTB-1, at 19-20; DPU-NECEC-1-4, Att.; EFCA-TW/MW-1, at 27-29; RR-DPU-27, Att.; NECEC Reply Brief at 5; Vote Solar Brief at 12, n.8, citing Exh. NECEC-RTB-1, at 19-20; RR-DPU-27, Att.; DPU-9-8, Att.).[302]

According to the Limited Intervenors, a tiered customer charge based on a customer's maximum monthly kWh use as a proxy for non-coincident peak demand is an inferior metric because it does not link rate design to the distribution system peak loads that drive distribution system costs (Acadia Center Brief at 15, citing Exh. AC-AA-Rebuttal-1, at 1-2; Acadia Center Reply Brief at 8-9; EFCA Brief at 16; NECEC Brief at 11; NECEC Reply Brief at 4; Vote Solar at 9-10, 12, 13, citing Fitchburg Gas and Electric Light Company 375 Mass. at 582). Vote Solar and NECEC contend that system costs are incurred based on customer's demand coinciding with collective peak demand of all customers, which Vote Solar claims that the Company acknowledges (NECEC Reply Brief at 4; Vote Solar Brief at 13-14, citing Exhs. NG-PP-1, at 31; VS-NP-1, at 27; EFCA-TW/MW-1 at 26-27; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, EFCA and Vote Solar claim that the Company did not perform an analysis showing that non-coincident peak demand charges actually reflect a customer's contribution to system costs, improve system utilization, cause customers to shift use in a way that reduces use during peak system hours, or reduce system costs (EFCA Brief at 16; NECEC Brief at 16; NECEC

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302 EFCA contends that the Company acknowledges its analysis was inadequate, and Vote Solar maintains that the Company admitted its tiered customer charge proposal was a "second-best solution" (EFCA Reply Brief at 11, citing Tr. 5, at 688; Vote Solar Brief at 2, 10, n.6, citing Exh. NG-PP-1, at 31; Tr. 5, at 637).

Reply Brief at 3-4; Vote Solar at 14, citing Tr. 5, at 677-679). NECEC maintains that distribution system costs are highly dependent on the time of day and the time of year that services are used, and distribution system costs result from the infrastructure needed to provide service during times of the highest customer use (NECEC Brief at 11-12, citing Exhs. NECEC-RTB-1, at 18; VS-NP-Rebuttal-1, at 7; Tr. 5, at 666-667, 774; Vote Solar Brief at 13, citing Exhs. NG-PP-1, at 31; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, Vote Solar asserts that the Company admitted that reductions in customer use during peak hours benefit the system and reduces costs (Vote Solar Brief at 13, citing Tr. 5, at 681). NECEC maintains that rate design should be based on costs incurred during times when demand is the highest (NECEC Brief at 12, citing Exhs. NECEC-RTB-1, at 18; AC-AA-Rebuttal-1, at 1; EFCA-TW/MW-1, at 26-27; VS-NP-1, at 27; VS-NP-Rebuttal-1 at 7; Tr. 5, at 774). Given these considerations, the Limited Intervenors claim the tiered customer charges, based on an individual customer's non-coincident peak demand, is not an improvement over standard volumetric charges and does not improve cost-causation (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 8, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 15, citing Exh. EFCA-TW/MW-1, at 25; NECEC Brief at 16-19; NECEC Reply Brief at 5; Vote Solar Brief at 12-15; Vote Solar Reply Brief at 6).

NECEC argues that the Company's proposed Phase I rates and current rates are more reflective of the cost to serve than the Company's proposed Phase II rates (NECEC Brief at 15-16, citing Exhs. AG-SJR-20-30; AG-SJR-6; AG-SJR-7; AG-SJR-8). For example, NECEC claims that under Phase I rates, a $1 increase in cost of service would correspond to a 57 cent increase in revenue recovery, but under Phase II rates, the same $1 increase would

correspond to only a 54 cent increase in revenue recovery (NECEC Brief at 16, citing Exhs. AG-SJR-1, at 22-23; AG-SJR-7; AG-SJR-8).

EFCA takes issue with Company's argument that a customer's maximum demand represents a customer's potential to contribute to the capacity requirements of the distribution system (EFCA Reply Brief at 10-11, citing Company Brief at 220-221; Exh. EFCA-TW/MW-1, at 25). According to EFCA, a customer's individual peak demand will not put the greatest strain on the system because individual peaks do not occur at the exact same time for all customers (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13).

Further, the Limited Intervenors argue that the Company's counter argument that existing distribution demand charges already are based on non-coincident peak demand is flawed (Acadia Center Reply Brief at 8-9; EFCA Reply Brief at 10-11; NECEC Reply Brief at 4; Vote Solar Reply Brief at 7). In particular, Acadia Center contends that the Company does not explain why non-coincident peak demand is the basis of existing demand charges, and argues that metering limitations are a primary reason that existing demand charges are based on the non-coincident peak demand during a billing period (Acadia Center Reply Brief at 9). According to Vote Solar and NECEC, existing demand charges for large C&I customers do not justify application of such charges to small C&I and residential customers because these customers do not use the distribution system in the same way (Vote Solar Reply Brief at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12-13, citing Exhs. NECEC-RTB-1, at 27; VS-NP-1, at 27; NECEC Reply Brief at 4-5). Further, Vote Solar maintains that many small customers share one feeder, creating diversity of demand, whereas a medium or large C&I customer can comprise the majority of demand on an individual feeder (Vote Solar Reply Brief

at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12, n.5, citing NECEC-RTB-1, at 27, 29; VS-NP-1, at 27; VS-CP-Rebuttal-1, at 12-13; NECEC Reply Brief at 5). Moreover, NECEC contends that peak demand drives that the size and costs of the distribution system (NECEC Brief at 12, citing Exh. NG-PP-1, at 30, 33; NG-PP-Rebuttal-1, at 13; AG-SJR-Rebuttal-1, at 15; NG-PP-2; Tr. 10, at 1557-1558, 1574-1575). Thus, EFCA, Vote Solar, and NECEC argue that the Company's proposed Phase II rate design approach ignores diversity of demand, discussed in planning for distribution system investment (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13; NECEC Brief at 11; NECEC Reply Brief at 4-5; Vote Solar Reply Brief at 7).

Finally, according to NECEC, tiered customer charges are an inaccurate measure of cost causation for customers who have installed solar DG (NECEC Brief at 20). NECEC maintains that solar DG customers typically reduce demand during summer months and are likely to have higher demand during off-peak months on the distribution system (NECEC Brief at 20, citing Exh. NECEC-RTB-1, at 21-24). Accordingly, NECEC asserts that tiered customer charges fail to provide accurate price signals indicating the value that solar DG provides in reduced costs on the distribution system (NECEC Brief at 21).

(F) Conclusion

In sum, the Limited Intervenors argue that the record does not support a finding that the Company's tiered customer charge proposal is just and reasonable (Acadia Center Brief at 2; EFCA Brief at 11; NECEC Reply Brief at 9-10; Vote Solar Brief at 7, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 264, n.13 (2002)). Further, Vote Solar claims that no other utility uses a rate design similar to the Company's proposed tiered

customer charges (Vote Solar at 3, citing Exh. DPU-2-12; Tr. 5, at 640). Therefore, the Limited Intervenors conclude that National Grid has not met its burden to justify the tiered customer charge proposal, and the Department should reject it (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 3; Vote Solar at 9, citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 582 (1978)).

iii. Seasonal Rate Design

Acadia Center and NECEC support the Attorney General's seasonal rate design proposal (Acadia Center Brief at 2, 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30). According to NECEC, the Department stated that it would consider seasonally differentiated rates where they were shown to more effectively indicate the underlying costs of the distribution system and encourage efficient consumption of electricity (NECEC Brief at 29, citing D.P.U. 10-70, at 330). Acadia Center and NECEC allege that the Attorney General's rate design proposal improves the relationship to cost of service compared to the Company's Phase I and Phase II rate design proposal (Acadia Center Brief at 17, 18; NECEC Brief at 29, citing Exhs. AG-SJR-1, at 22-24, 30; AG-SJR-7; AG-SJR-8; AG-SJR-12).

Acadia Center and NECEC also argue that the Attorney General's seasonal rate design meets the Department's rate making goals (Acadia Center Brief at 18; NECEC Brief at 29-30). They assert that the seasonal rate design is cost-based, results in reasonable bill impacts, is simple and understandable, and improves efficiency and cost causation (Acadia Center Brief at 18; NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 27-28, 30; NECEC-RTB-Rebuttal-1, at 3, 12; EFCA-TW/MW-Rebuttal-1, at 22-23).

Further, NECEC argues that a higher rate in the summer months would better align time of use with underlying costs (NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 16-20; AG-SJR-2; AG-SJR-4; AG-SJR-5). In this regard, NECEC contends that bill impacts range from 10 percent to 38 percent (compared to negative 14 percent to 181 percent under the Phase II rate design proposal) (NECEC Brief at 29, citing Exh. SG-SJR-1, at 27-28, 30). According to NECEC, the Rate G-1 seasonal rate design has similar bill impacts to the Company's proposed Phase I rate design (NECEC Brief at 30, n.15, citing RR-DPU-47; Tr. 10, at 1569-1570). Finally, NECEC asserts that seasonal rates are more efficient, do not require advanced meters, and can be implemented in conjunction with time-varying rates (NECEC Brief at 30, citing D.P.U. 14-04-C; Exhs. EFCA-TW/MW-Rebuttal-1, at 22-23; NECEC-RTB-Rebuttal-1, at 12-13).

NECEC also argues that the Company disputed the Attorney General's proposed seasonal rate design with two, unconvincing arguments (NECEC Reply Brief at 13). First, NECEC rejects the Company's argument that system-wide coincident peak demand reduction from a seasonal rate design is not beneficial because some feeders might not realize a reduction in their peak demand, as NECEC notes that the majority of the Company's feeders peak in the summer (NECEC Reply Brief at 14, citing Exhs. NECEC-RTB-Rebuttal-1 at 9-10; NG-PP-Rebuttal-1, at 14-15; NECEC-1-7; Company Brief at 224). Thus, NECEC asserts it cannot be disputed that for nearly all feeders, summer electricity use is the driver of demand-related system costs (NECEC Reply Brief at 14, citing Company Brief at 199, 217).

Second, NECEC rejects the Company's argument that seasonal rates will result in "arbitrarily" higher net metering credits (NECEC Reply Brief at 14, citing Company Brief

at 224). According to NECEC, the higher value of net metering credits in the summer months from the Attorney General's proposed seasonal rate design are not "arbitrary" because the value of net metering credits will rise with summer distribution rate (NECEC Reply Brief at 14). Further, NECEC contends that a higher summer rate is appropriate because cost responsibility for the majority of demand-related costs is based on the customer class contribution to summer peak demands in the Company's allocated COSS (NECEC Reply Brief at 14, citing Exhs. AG-SJR-1, at 17, 29-30; AG-SJR-Rebuttal-1, at 15-16). Therefore, NECEC asserts that there is nothing arbitrary about crediting excess generation from net metering facilities at a higher rate when that rate accurately reflects the increased value of the demand reduction associated with that generation during the summer months (NECEC Reply Brief at 14).

e. AIM and TEC

AIM and TEC argue that National Grid did not properly support its demand ratchet proposal for Rates G-2 and G-3 and did not analyze the impacts of the demand ratchet proposal on current customers (AIM and TEC Reply Brief at 8). According to AIM and TEC, the Company's own evidence contradicts its basis for proposing the demand ratchet (AIM and TEC Reply Brief at 8). For example, AIM and TEC contend that Rate G-3 customers' demand patterns show that the Rate G-3 class load is different than demand during the monthly system coincident peak (AIM and TEC Reply Brief at 5, citing Exh. NG-PP-3(b)). AIM and TEC claim that this data contradicts the Company's assertion that a customer's maximum demand during an annual period reflects the customer's contribution to coincident peak demand (AIM and TEC Reply Brief at 5). According to AIM and TEC, National Grid sizes its circuits to accommodate coincident peak demand, not the summation of non-coincident peak demands (AIM and TEC

Reply Brief at 5). Thus, AIM and TEC contend that cost causation occurs when a customer's peak demand coincides with the maximum monthly peak demand (AIM and TEC Reply Brief at 5). Therefore, AIM and TEC claim that because a demand ratchet does not account for the timing of a customer's demand, and its coincidence with system peak, and because it fails to reflect cost causation, the demand ratchet results in a fixed annual charge (AIM and TEC Reply Brief at 7). Accordingly, AIM and TEC assert that the Department should reject the Company's claim that all Rate G-2 and Rate G-3 customers pay for demand through a demand ratchet that is based on their annual peak load, regardless of when it occurs (AIM and TEC Reply Brief at 5).

Further, AIM and TEC argue that the demand ratchet proposal will reduce customer incentives for behavior that is beneficial to the system and demand reduction goals (AIM and TEC Reply Brief at 7). AIM and TEC agree with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth because it operates as a fixed charge (AIM and TEC Reply Brief at 7-8).

Moreover, AIM and TEC argue that the demand ratchet is really a "de facto" stand-by charge for customer's with behind the meter DG because these customers will not be able to reduce their demand charge for an entire year (AIM and TEC Reply Brief at 4, 6, 8). In this regard, AIM and TEC contend that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages (e.g., combined heat and power ("CHP")) without recognizing the benefit of demand reductions that could reduce system costs for all customers (AIM and TEC Reply Brief at 6). For example, AIM and TEC claim that a customer with a 30-minute CHP outage during a month that the grid has excess capacity (e.g., April) could result in additional demand charges of over $21,000 for that twelve-month period (AIM and TEC

Reply Brief at 6). Further, AIM and TEC maintain that some customers with DG must interrupt on-site generation when there are power quality issues completely beyond the customer's control (AIM and TEC Reply Brief at 6). Moreover, AIM and TEC note that current DG owners schedule maintenance during off-peak periods to avoid demand charges (AIM and TEC Brief at 7). According to AIM and TEC, a demand ratchet eliminates the incentive to schedule maintenance during off-peak periods because demand charge cost avoidance can no longer justify the added cost of overtime and weekend labor rates for the off-peak work (AIM and TEC Reply Brief at 7). Thus, AIM and TEC assert that the Company's demand ratchet proposal will unfairly penalize these customers and cause negative impacts for customers with distributed resources (AIM and TEC Reply Brief at 6-7).

AIM and TEC also take issue with National Grid's hypothetical customer example, and they argue that it represents a business only operating in the summer and thereby only paying a demand charge during the summer, but requiring a fixed distribution investment from the Company to accommodate this customer's peak load (AIM and TEC Reply Brief at 4-5, citing Exh. NG-PP-1, at 59). AIM and TEC contend that the scenario the Company modeled to support its proposal for a demand ratchet is rare and should not be used to justify a new charge applying to all customers (AIM and TEC Reply Brief at 5).

In light of these considerations, AIM and TEC argue that the Company has not carried its burden of proof to warrant approval of the proposed demand ratchet (AIM and TEC Reply Brief at 8, citing D.T.E. 99-118, at 7, n.5). Additionally, AIM and TEC argue that the Company's rationale for its demand ratchet proposal is confused, illogical, and flawed, and the Company's proposal violates the Department's rate design principles (AIM and TEC Reply Brief at 4, 7-8).

Thus, AIM and TEC recommend that the Department reject the Company's demand ratchet proposal (AIM and TEC Reply Brief at 10).

f. PowerOptions

i. Demand Ratchet

PowerOptions argues that the Company did not properly support its demand ratchet proposal for Rate G-2 and Rate G-3 because it did not provide evidence of the impacts of the demand ratchet proposal on current customers (PowerOptions Reply Brief at 5-7). Further, PowerOptions claims that the Company's demand ratchet proposal is a sweeping change in the manner of billing medium and large C&I customers (PowerOptions Reply Brief at 6).

PowerOptions argues that the Company's demand ratchet operates as a fixed charge (PowerOptions Reply Brief at 7). According to PowerOptions, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" because it provides little incentive to reduce demand each month after the peak has been set (PowerOptions Reply Brief at 7).[303] Therefore, PowerOptions contends that a fixed demand charge does not account for the timing of customer demand and its coincidence with the system peak, and also fails to reflect cost causation (PowerOptions Reply Brief at 7). Thus, PowerOptions claims that the demand ratchet proposal is unfair and causes negative impacts for customers with distributed resources (e.g., solar) (PowerOptions Reply Brief at 7).

Further, according to PowerOptions, the Company's billing demand definitions are confusing for customers (PowerOptions Reply Brief at 6). PowerOptions maintains that

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303 PowerOptions agrees with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth (PowerOptions Reply Brief at 7, citing DOER Brief at 5).

calculating a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months is unclear (PowerOptions Reply Brief at 6). Therefore, PowerOptions argues that customers will be unable to manage their facilities appropriately (PowerOptions Reply Brief at 6). Accordingly, PowerOptions asserts that the Department should reject the Company's demand ratchet proposal (PowerOptions Reply Brief at 8).

ii. Tiered Customer Charges

PowerOptions argues that a tiered customer charge rate structure based on maximum demand is not appropriate for residential or small commercial customers (PowerOptions Reply Brief at 3). In this regard, PowerOptions contends that these customers cannot appropriately adapt or respond to a tiered customer charge structure without having advanced metering, demand meters, or appropriate technology to know when they are reaching their peak use (PowerOptions Reply Brief at 4). Further, PowerOptions maintains that National Grid did not sufficiently demonstrate that using non-coincident peak demand actually reflects a customer's contribution to distribution system costs, and, as such, it is the appropriate tool for charging distribution rates (PowerOptions Reply Brief at 4, citing NECEC Brief at 11, 13).

Moreover, PowerOptions argues that the Company's Phase II proposal removes the link between a customer's energy conservation and seeing reduced charges on the electric distribution bill because a customer must maintain a year of reduced monthly use to drop to a lower tier (PowerOptions Reply Brief at 3). PowerOptions contends that the tiered customer charge proposal risks undermining one of the Commonwealth's energy policy goals of maximum deployment of energy efficiency (PowerOptions Reply Brief at 4, citing DOER Brief at 7). Further, PowerOptions claims that the delay in monetary savings from the implementation of

energy efficiency measures inherent in National Grid's tiered customer charge proposal could discourage these investments and impact the Commonwealth's energy goals (PowerOptions Reply Brief at 4). Additionally, PowerOptions asserts that National Grid has not analyzed how the tiered customer charge proposal may affect the achievement of its three-year energy efficiency plan (PowerOptions Reply Brief at 4-5, citing DOER Brief at 7).

Finally, PowerOptions maintains that the Company's proposal is not consistent with the Department's "standard of review" (PowerOptions Reply Brief at 3). Based on all of these reasons, PowerOptions asserts that the Department should reject the Company's tiered customer charge proposal (PowerOptions Reply Brief at 3, 5).

iii. Seasonal Rate Design

PowerOptions supports the Attorney General's seasonal rate design proposal (PowerOptions Reply Brief at 5). PowerOptions maintains that it is easier for customers to understand than the Company's Phase II proposal and enables customers to respond to price signals (PowerOptions Reply Brief at 5). PowerOptions argues that there is a much stronger correlation between peak-season energy consumption and peak demand than the Company describes (PowerOptions Reply Brief at 5, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Thus, PowerOptions maintains that the Attorney General's seasonal rate design proposal links distribution prices to summer distribution peaks (PowerOptions Reply Brief at 5). According to PowerOptions, the seasonal rate design proposal is cost-based, results in reasonable bill impacts, is simple and understandable, improves efficiency and cost causation, and therefore, meets the Department's rate design goals (PowerOptions Reply Brief at 5, citing NECEC Brief at 30).

g. Company

i. Overview

National Grid argues that the appropriate regulatory forum to determine rate design is in a general rate case, based on the revenue requirement and cost studies used to establish "just and reasonable" rate design (Company Reply Brief at 83-84). According to the Company, its rate structure should consist of customer charges, demand charges, and consumption charges that are reflective of customer-related, demand-related and consumption-related costs, respectively (Company Reply Brief at 84). National Grid contends that its proposal is "the first step in a process towards an optimal rate design, which would include both customer and demand charges for each rate class" (Company Brief at 214).

Moreover, the Company maintains that its proposed rate design properly balances the Department's rate design goals: efficiency, simplicity, continuity, fairness, and earnings stability (Company Brief at 202, citing Exh. NG-PP-1, at 29; Company Brief at 211, 213-214). According to the Company, its rate design: (1) produces the desired revenue for each rate class determined in its allocation process; (2) generates revenue that is reasonably stable and predictable while reflecting cost-causation principles; (3) reflects the cost to serve and to ensure adequate revenue to the utility; (4) mitigates extreme bill impacts on customer groups; and (5) results in equalized rates of return amongst all rate classes pursuant to § 94I (Company Brief at 202, citing Exh. NG-PP-1, at 46-47). Therefore, the Company asserts that the Department should approve the Company's proposed rate design in this case (Company Reply Brief at 84).

The Company explains that its primary objective in its rate design proposal is customer equity and to design rates that reflect the actual relative cost to serve each customer (Company

Brief at 203, citing Exh. NG-PP-1, at 23; Company Reply Brief at 83). However, the Company argues that there are limitations in establishing the cost to serve customers and the ability to design rates that recover those costs (Company Brief at 212). In particular, National Grid contends that costs are determined for groups of homogeneous customers with similar cost-causation attributes, not for individual customers (Company Brief at 212, citing Exhs. NG-PP-1, at 39-41; AG-12-2). Further, the Company claims that the Department's rate design goals of simplicity, continuity, and earnings stability often lessen the cost-basis in rate design implementation (Company Brief at 212). Additionally, the Company maintains that it considers the cost and availability of meters in designing rates (Company Brief at 212).

The Company supports transparent and efficient rate designs that provide sufficient revenue to support the distribution system, motivate the appropriate behaviors, and assure fairness and equity among customers (Company Brief at 213). According to National Grid, both DG and non-DG customers impose demand on the distribution system and its associated services (Company Brief at 213). However, the Company asserts that distribution service provided to DG customers is being paid for, in whole or in part, by all customers through revenue decoupling and net metering credits[304] (Company Brief at 213). In this regard, National Grid notes that it recovers the bulk of distribution service costs through the volumetric portion of distribution rates (Company Brief at 213). Further, the Company contends that net metering allows DG customers to zero out bills and to build credits towards their cost for future electricity consumption (Company Brief at 214). The Company contends that this policy has enabled many customers to

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304 The Company reports that net metering caps are over-subscribed, and it provided approximately $64 million of net metering credits to DG customers in 2015 (Company Brief at 215, citing Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3; Tr. 7, at 1043)

avoid payment for their use of the distribution system (Company Brief at 214). Therefore, the Company maintains that the current DG landscape and its rate design creates a growing cost-shift within the Company's service territory, while providing little benefits (Company Brief at 213-215, citing Exh. NG-PP-Rebuttal-1, at 37).

Finally, the Company argues that the price for distribution service should reflect the value and true cost of the service, and customers' bills should reflect each customer's demand for such service (Company Brief at 213). According to National Grid, current rate design does not properly attribute costs caused by customers with DG facilities to those customers, but its rate design proposal appropriately addresses cost responsibility for DG customers (Company Reply Brief at 83-84, 212). The Company contends that if rate design is not based on cost causation, customers that do not use DG facilities are cross-subsidizing those customers with DG facilities (Company Reply Brief at 83, 212).[305] Further, National Grid claims that the Limited Intervenors are employing delay tactics that ignore the impact on rates and cost recovery caused by the rapid development of DG facilities in Massachusetts (Company Reply Brief at 83).

ii. Demand Ratchets

National Grid argues that those opposing the Company's demand ratchet proposal do not dispute the ratemaking objective of demand ratchets, but rather, oppose the demand ratchets' effect on energy efficiency, solar DG, and storage (Company Brief at 226; Company Reply Brief

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[305] According to the Company, it collects most of its costs through usage charges (Company Reply Brief at 84). The Company contends that the usage of a customer with a DG facility behind-the-meter may drop or vary from the baseline used to establish rate design (Company Reply Brief at 84). Therefore, the Company maintains that the relationship between cost incurrence and revenue collection is broken and the recovery of costs is shifted to other customers (Company Reply Brief at 84).

at 92). The Company asserts that such opposition lacks merit (Company Brief at 227; Company Reply Brief at 93).

In particular, National Grid rejects any arguments that a demand ratchet delays payback periods for energy efficiency and demand reduction investments, and the Company instead notes that its demand ratchet analysis shows little impact on customer savings from the implementation of energy efficiency because approximately 70 to 75 percent of energy efficiency savings result from reductions in kWh use (Company Brief at 227, citing Exh. NG-PP-Rebuttal-1, at 28; Company Reply Brief at 93). Further, National Grid maintains that the record demonstrates that a demand ratchet has little impact on a customer installing energy efficiency or demand reduction technologies (Company Brief at 227, 228; Company Reply Brief at 93, 94). According to the Company, it calculated a $200 to $400 reduction, from total savings ranging from $26,000 to $57,000, in the first year of an energy efficiency investment, due to the demand ratchet (Company Brief at 227, citing Exh. DPU-15-16, Att. at 3-4; Company Reply Brief at 93). Moreover, the Company argues that with or without the demand ratchet, the customer will accumulate all of the annual savings associated with energy efficiency investments after the first investment year (Company Brief at 227-228; Company Reply Brief at 93-94).

Regarding the installation of a demand reduction investment (i.e., DG or storage), the Company maintains that customer savings on an installation that reduces 50 percent of kW and kWh billing determinants reduced savings by 2.6 percent for the first year (from approximately $205,800 to $193,800) as a result of the demand ratchet (Company Brief at 228, citing Exh. DPU-15-16, Att. at 5; Company Reply Brief at 94). Therefore, National Grid

contends that demand ratchets will not cause a disincentive to invest in energy efficiency or demand reduction technologies (Company Brief at 228; Company Reply Brief at 94).

Further, the Company argues that a demand ratchet is reasonable and appropriate for Rate G-2 and Rate G-3 customers because it will assess demand charges based upon each customer's maximum demand during the year (Company Brief at 208; Company Reply Brief at 92). The Company notes that its system was designed and built to accommodate maximum aggregate demand of all customers at a single point in time (Company Brief at 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Thus, the Company asserts that its proposal will better reflect a customer's contribution to coincident demand, and it will result in cost recovery more reflective of the costs that are incurred to serve that customer (Company Brief at 208, 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Consequently, National Grid asserts that it has demonstrated that the demand ratchet for Rates G-2 and G-3 is reasonable, and that its proposal should be approved (Company Brief at 228; Company Reply Brief at 94).

iii. Tiered Customer Charges

National Grid argues that its Phase II rate design proposal is a reasonable change in rate structure to move rates for residential and small commercial customers toward the recovery of customer-related and demand-related costs to serve (Company Brief at 225; Company Reply Brief at 91). According to the Company, a higher customer charge for higher-use customers is a reasonable proxy to recover the higher demand-related costs imposed on the distribution system by these customers (Company Brief at 225; Company Reply Brief at 91). The Company asserts that its proposal is consistent with the Department's rate structure goals and objectives, and, therefore, it should be approved (Company Brief at 225; Company Reply Brief at 91).

According to the Company, a distribution system is sized and constructed to accommodate the maximum demand on the system at a single point in time, and, once constructed, distribution system costs are fixed in nature (Company Brief at 217, 218, citing Exhs. NG-PP-1, at 33, 38; Company Reply Brief at 85, 86). The Company maintains that a customer's monthly maximum kWh use during a 12-month period reflects the customer's contribution to total system demand and should be the basis for the customer's cost responsibility in rate design instead of a customer's monthly or annual kWh consumption (Company Brief at 217, 218, citing Exh. NG-PP-1, at 38-39; Company Reply Brief at 85, 86). Therefore, the Company contends that its Phase II rate design proposal better aligns the recovery of fixed distribution system costs than the current single customer charge for these rate classes and results in a more equitable contribution to costs by all customers on the basis of their size (Company Brief at 217, 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 85, 86). Further, National Grid argues that a reduction in energy consumption does not necessarily result in a corresponding reduction in distribution costs (Company Brief at 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 86). According to the Company, the Phase II rate design proposal is a reasonable proxy for a rate structure in which a fixed customer charge recovers the customer related cost to serve each customer and a demand charge based on customer size recovers capacity-related costs (Company Brief at 217, citing Exh. EFCA 1-1; Company Reply Brief at 85).

The Company disagrees with the argument that the adoption of the tiered customer charge would be inconsistent with § 141 (Company Brief at 222, citing Low Income Network Brief at 17-26; Vote Solar Brief at 22-23; Company Reply Brief at 88, citing Low Income

Network Reply Brief at 5-7; NECEC Reply Brief at 12-13; Vote Solar Reply Brief at 11-13). The Company argues that interpreting the statue to ban any rate design that would affect existing incentives for DG and energy efficiency is not consistent with the plain language of that statute (Company Brief at 222; Company Reply Brief at 88). Rather, according to the Company, a reasonable reading of the statutory language is that the Department is required to consider the impacts of the Company's proposed rate design along with the increased incentives that are provided to energy efficiency and on-site generation (Company Brief at 222 (emphasis in original); Company Reply Brief at 88-89). The Company maintains that the Department must balance the various interests (i.e., rate design and incentives for energy efficiency and DG), which the Company advocates for in its rate design proposals (Company Brief at 222; Company Reply Brief at 89).

Further, in response to the argument that the tiered customer charges do not reflect the demand-related costs that individual customers put on the system and that they do not consider the timing of the customer's non-coincident peak and peak demand, the Company asserts that existing demand charges are based on a customer's maximum demand (Company Brief at 220; Company Reply Brief at 87). For example, the Company argues that demand charges for C&I customers are assessed on the customer's maximum kW because it represents the customer's potential to contribute to the capacity requirements of the distribution system (Company Brief at 220-221, citing Exh. NG-PP-Rebuttal-1, at 14; Company Reply Brief at 87, citing Exh. NG-PP-Rebuttal-1, at 14). Therefore, the Company asserts that a demand charge designed to recover demand-related distribution costs billed to the customer on maximum

monthly demand is not new or unreasonable (Company Brief at 221; Company Reply Brief at 87).

Further, in response to the argument that the tiered customer charge proposal is not an improvement over the current rate design, the Company argues that its detailed analysis refutes the claim (Company Brief at 223, citing Exh. NG-PP-Rebuttal-2; Company Reply Brief at 89 citing Exh. NG-PP-Rebuttal-2). According to the Company, the analysis comparing bill charges resulting from: (1) the existing rate design; (2) the proposed residential Phase I rate design; (3) the proposed residential Phase II rate design reflecting tiered customer charges; and (4) a rate design that includes separate customer and demand charges, demonstrates that, for both high- and low-load factor customers, its Phase II proposal charge more closely approximates the rates based on separate customer and demand charges (Company Brief at 223, citing Exh. NG-PP-Rebuttal-1, at 12; Company Reply Brief at 89). In addition, National Grid argues that its Phase II rate design proposal does not produce monthly bills that are significantly different from those under either the current rate structure or its proposed Phase I rate design (Company Brief at 223; Company Reply Brief at 89). Therefore, the Company asserts that its Phase II proposal fulfills the Department's rate continuity goal (Company Brief at 223; Company Reply Brief at 89).

National Grid also rejects any arguments that its proposed tiered customer charge structure is confusing and provides insufficient price signals (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). The Company contends that such

arguments are contradictory to the notion that customers demand more time varying rates (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). In this regard, the Company argues that although its proposal is based on the concept that customer demand underlies the basis for the tiered customer charge, the actual structure of the rates (i.e., a customer charge and a per-kWh rate) does not change (Company Brief at 224-225, citing Exh. NG-PP-Rebuttal-1, at 30; Company Reply Brief at 90-91).

Moreover, while National Grid acknowledges that customers might not be familiar with the concept of demand, the Company argues that customers understand the implications on the distribution system resulting from changes in electricity consumption (Company Brief at 224, n.44, citing docket D.P.U. 10-82, evaluation report of the Company's Smart Energy Solutions Program; Company Reply Brief at 90 n.20). Further, the Company claims that its outreach and education program will resolve any customer confusion about its Phase II rate design proposal (Company Brief at 225; Company Reply Brief at 91). In particular, the Company maintains that it proposed a six month delay in its Phase II rate design effective date "to educate customers on the reason behind and determination of the tiered customer charges, including changes to their bills and ways to reduce usage to take advantage of tiers with lower customer charges" (Company Brief at 225, citing Exh. NG-PP-Rebuttal-1, at 31; Company Reply Brief at 91).

iv. Seasonal Rate Design

National Grid opposes the alternative seasonal rate design proposal recommended by the Attorney General and others, as the Company claims that there is no cost basis for the 15-percent

differential between summer and winter rates (Company Brief at 224; Company Reply Brief at 90; see Attorney General Brief at 137; Attorney General Reply Brief at 72, 76; Acadia Center Brief at 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30; NECEC Reply Brief at 3, 6, 10, 12, 13). According to the Company, "while there is little data identifying a peak load during the non-summer months of October through May, many feeders may experience non-summer peak demands that are very close to their summer peak demand" (Company Brief at 223-224, citing Exh. VS-2-12; Company Reply Brief at 89). Further, the Company contends that a summer-peaking feeder may become winter peaking during extremely cold weather, and that transition reduces the differences between summer and winter peak demands (Company Brief at 224; Company Reply Brief at 89-90). Further, National Grid claims that increasing solar generation affects summer demand far greater than winter demand, further increasing the probably of peak loads shifting from the summer months to the winter months in the future (Company Brief at 224; Company Reply Brief at 90). Therefore, the Company argues that "a system-wide reduction in coincident peak demand may not result in a commensurate reduction in actual or forecasted peak demand for each feeder" (Company Brief at 224; Company Reply Brief at 90). Finally, the Company asserts that setting a summer rate 15 percent higher than a winter rate will produce arbitrarily higher net metering credits (Company Brief at 224; Company Reply Brief at 90).

6. Analysis and Findings

In ruling on the Company's rate design proposals, the Department considers its rate design goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-80/D.P.U. 15-81,

at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.

a. Demand Ratchets

DOER, EFCA, AIM and TEC, and PowerOptions, oppose the Company's demand ratchet proposal. The Company previously proposed to implement demand ratchets, and the Department denied the Company's request. Massachusetts Electric Company, D.P.U. 85-146, at 68-69 (1986). In denying the demand ratchet proposal, the Department found that demand ratchets can, in an uneconomic manner, provide no incentive to reduce demand beyond the class or system peak and little incentive to reduce kWh use. D.P.U. 85-146, at 69. Moreover, we determined that a demand ratchet distorts the price signal to the customers and discourages customers from investing in load control equipment that would otherwise be cost-effective. D.P.U. 85-146, at 68; see also D.P.U. 84-145-A at 125. Further, the Department has found that demand ratchets are inappropriate because they distort incentives to conserve electricity and could unfairly impose higher costs on certain customers. Western Massachusetts Electric Company, D.P.U. 94-101/95-36, at 50 (1995); D.P.U. 92-78, at 188; Western Massachusetts Electric Company, D.P.U. 86-280, at 196 (1987); D.P.U. 84-25, at 199.

Further, the Company did not present any particularly compelling argument that would persuade the Department to alter its precedent on this matter.[306] In particular, the Department finds that the Company failed to provide sufficient evidence to demonstrate that a customer would have any incentive to reduce their demand after it reaches its annual peak demand. Therefore, we find that the Company's proposed demand ratchet is inconsistent with the aforementioned Department precedent, as well as the Department's goals of efficiency and fairness. As such, the Company's demand ratchet proposal is denied. Accordingly, the Department directs the Company in its compliance filing to revise its proposed demand charges for Rates G-2 and G-3 to eliminate the demand ratchet component. Instead, the Company shall design the demand rates consistent with the definition of billing demand found in its currently effective Rates G-2 and G-3 tariffs, M.D.P.U. Nos. 1152 and 1153 (respectively for MECo) and M.D.P.U. Nos. 526 and 527 (respectively for Nantucket Electric).

b. Tiered Customer Charges

National Grid's tiered customer charge proposal is premised on the Company's position that under its current rates there is a shift in cost recovery from DG customers to non-DG customers (Exh. NG-PP-Rebuttal-1, at 53). The tiered customer charges are designed to mitigate that cost-shift by using a customer's highest monthly energy use as a proxy for that customer's peak demand, thereby employing a rate design that captures the cost that a customer imposes on

306 The Department recognizes that it accepted demand ratchets as a reasonable resolution of the issue of undue discrimination in allowing standby rates, but only in the context of a Settlement Agreement between NSTAR Electric, DOER, AIM, CLF, the Joint Supporters and SEBANE. NSTAR Electric Company, D.T.E. 03-121, at 42 (2004). In approving the Settlement Agreement, the Department's decision in that proceeding was not intended to represent a fully litigated review on the merits resulting in a wholesale change in rate making policy. D.T.E. 03-121, at 42 n.16.

the distribution system from the customer's individual peak demand (Exhs. NG-PP-1, at 32-35; NG-PP-Rebuttal-1, at 10; DPU-9-14). The Attorney General, DOER, the Low Income Network, the Limited Intervenors, and PowerOptions oppose the Company's tiered customer charge proposal.

The Company purports that "DG customers may contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers" (emphasis added) (Exh. NG-PP-1, at 28). The Company has not quantified the amount of costs attributable specifically to DG customers and has not quantified the distribution system benefits associated with DG customers in its service territory (Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; LI-1-10, at 1; Tr. 5, at 620). Other than quantifying net metering credits and citing to current rate design, the Company did not substantiate its cost-shift assumption with reasonable analysis and quantitative record evidence (Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3, Att.). As such, the Department is not persuaded that a cost-shift from DG customers to non-DG customers, in fact, exists. Therefore, we find that the basis of the Company's tiered customer charge proposal is not sufficiently supported.

Further, § 141 states, in part: "[i]n all decisions or actions regarding rate designs, the [D]epartment shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation." The Company's tiered customer charge proposal shifts cost recovery away from the volumetric, per-kWh charges, causing kWh rates to decrease (Exh. NG-PP-1, at 32). As volumetric, per-kWh rates decrease, customers' incentives to install energy efficiency and on-site generation

diminish as potential savings are lower and net metering credits are lower. Further, the Company failed to provide evidence regarding the impact of its tiered customer charges on energy efficiency, compliance with the three-year energy efficiency plan, and incentives to lower demand (Exh. DOER-2-18; Tr. 5, at 634). Moreover, although pricing distribution service on demand use may support the cost-to-serve principle, it is not the best rate structure to promote energy efficiency. D.P.U. 10-70, at 332.

The Company's tiered customer charge proposal and demand ratchet proposals are similar in operation. Similar to the demand ratchet proposal, the Department finds that the Company's tiered customer charge proposal provides no incentive to lower demand and electricity use below the highest level within a tier. Additionally, the tiered customer charges distort incentives to conserve electricity, may unfairly impose higher costs on certain customers, and discourage customers from investing in cost-effective energy efficiency. D.P.U. 94-101/95-36, at 50; D.P.U. 92-78, at 188; D.P.U. 86-280, at 196; D.P.U. 85-146, at 68-69; D.P.U. 84-145-A, at 125; D.P.U. 84-25, at 199.

Next, the Department addresses whether the Company's tiered customer charge proposal meets our rate design goal of simplicity. National Grid's tiered customer charge proposal is a transition toward mandatory demand charges for residential and small C&I customers (Exh. NG-PP-Rebuttal-1, at 10-11). However, the Company failed to establish that demand charges are understandable by residential and small C&I customers. Additionally, although the Company planned to implement an outreach and education plan, by the close of the record it had not developed a detailed customer outreach and education plan at this time (Exh. VS-2-6; see Exhs. NG-PP-1, at 45; DPU-9-16). Further, the Company's proposal, including residential

demand charges, is not a mandatory residential rate design used by any state-regulated utility in the country (Exh. DPU-12-2; Tr. 5, at 638-641, 654-657). The Department is concerned that the Company has not determined its customers' tolerance and acceptance of a significant change in rate design, and therefore, has not presented adequate strategies to ensure that its customers will understand the tiered customer charge proposal.

Further, under the Company's proposal, customers lack the ability to monitor their electricity consumption throughout the month in real time (Tr. 7, at 1186-1187). Under the Company's inclining block rate structure, customers were not able to monitor their use to ascertain when or if it would be high enough to be billed at the tail block rate (Tr. 7, at 1186-1187). Further, customers will experience a lag between actual consumption, and the availability of the data and resulting customer charge tier (Exh. VS-2-7). Thus, customers do not have the equipment to easily monitor electricity consumption in real time and would be unaware if they were about to reach a new maximum monthly kWh use that would increase their customer charge. Accordingly, the Department finds that the Company's tiered customer charge proposal fails to meet the Department's rate design goal of simplicity.

Next, the Department addresses whether the Company's tiered customer charge proposal meets our rate design goal of efficiency. In support of its tiered customer charge proposal, National Grid provided analysis of approximately 12,300 residential and 300 small C&I load research customers' relationship between maximum annual kWh use and maximum demand use and concluded from this analysis that a customer's maximum kWh use can be used to approximate their demand, as measured in kW (Exhs. NG-PP-1, at 41; NG-PP-10). The Company reached this conclusion based on the fact that the maximum billed use explained more

than 50 percent of the variation in maximum hourly load, as measured by the R-squared[307] value of 0.6093 for residential and 0.7512 for small C&I (Exhs. NG-PP-1, at 41; NG-PP-10; WP-NG-PP-3; Tr. 5, at 687-689). However, the Company was unsure if it would have proposed tiered customer charges if the R-squared value was less than 0.5 (Tr. 5, at 692). In similar analyses comparing customers' maximum annual kWh use and maximum demand within each of the four proposed customer charge tiers, only one R-squared value was greater than 0.5 (Exh. DPU-9-8; Tr. 5, at 637-638).[308] Therefore, the Department finds that the Company's tiered customer charge proposal is inadequate for serving as a proxy for a customer's contribution to maximum demand (see Exh. AG-SJR-1, at 19). Additionally, the Company's current rate design is more reflective of the cost to serve and a better indicator of customer's maximum demand than is the Company's tiered customer charge proposal (Exhs. AG-SJR-20-30; EFCA-TW/MW-1, at 27-29; NECEC-RTB-1, at 19-20; DPU-9-8, Att.; DPU-NECEC-1-4; DPU-NECEC-1-5, Att.; RR-DPU-27, Att.).

For all of these reasons, the Department finds that the Company's tiered customer charges do not meet our rate design goals of simplicity and efficiency, and do not provide strong signals to consumers to decrease energy consumption in consideration of price and non-price,

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307 As noted, R-squared is a statistical measure of how close the data are to the fitted regression line and measures the strength of a relationship (Exh. DPU-15-9; Tr. 8, at 1218). In general, the higher the R-squared, the better the model fits the data (Exh. DPU-15-9). A R-squared value of one means that the model explains all the variability of the data, and a R-squared value of zero means that the model explains none of the variability of the data (Tr. 5, at 636).

308 For residential customers in Tiers 1, 2, 3, and 4, the analyses showed R-squared values of: 0.1911, 0.1352, 0.1134, and 0.4587, respectively (Exh. DPU-9-8, Att.). For Rate G-1 customers, the R-squared values for Tiers 1, 2, 3, and 4 were: 0.2306, 0.0576, 0.3617, and 0.5727, respectively (Exh. DPU-9-8, Att.).

social, resource, and environmental factors. Accordingly, we decline to accept the Company's Phase II, tiered customer charge rate design proposal.[309] The Department addresses rate design for Rates R-1, R-2, and G-1 in the Rate-by-Rate section, below.

c. Seasonal Rate Design

In the alternative to the Company's tiered customer charge proposal, the Attorney General proposed a seasonal rate design for Rates R-1 and R-2. This proposal is supported by Acadia Center, NECEC, and PowerOptions (Attorney General Brief at 134-135; Acadia Center Brief at 2, 17-18; NECEC Brief at 29-30; PowerOptions Reply Brief at 5).

The Department stated that it would consider seasonally differentiated rates, as well as other dynamic pricing alternatives to inclining block rates. D.P.U. 10-70, at 330. In considering "other dynamic pricing alternatives" in an investigation into time varying rates, the Department declined to implement time varying distribution rates. Time Varying Rates, D.P.U. 14-04-B at 13-14 (2014). We see no reason to deviate from that position here.

Moreover, the Attorney General's seasonal rate design proposal is only a slight improvement in cost-effectively collecting the cost to serve the distribution system compared to the Company's Phase I proposal (Exh. AG-SJR-1, at 30). For example, in an analysis of 12,056 residential customers comparing the cost of service and the Attorney General's proposed distribution bill, the seasonal rate design improves the relationship to cost increases by 0.004 R-square from 0.271 to 0.281, and the average variance between costs and revenues from 53 percent to 52 percent (Exhs. AG-SJR-1, at 30; AG-SJR-12). Annual bill impacts improve

309 Because the Department declines to adopt the Company's tiered customer charge proposal, we will not address continuity (i.e., bill impacts). In the Rate-by-Rate section, below, the Department considers continuity when determining each rate class's rate design.

slightly from a range of increases of 20 percent to 48 percent to 22 percent to 45 percent (Exh. AG-SJR-1, at 30). Further, residential customers already experience rate changes on March 1, May 1, and November 1 (Tr. 7, at 1182). Seasonal rates would establish additional mandatory rate changes on July 1 and October 1 (see Exh. AG-SJR-1, at 30). The Department finds that a "slight improvement" in rate design compared to the Company's Phase I proposal is outweighed by the potential for additional customer confusion and reduced simplicity in the Company's Phase I rate design. Based on the foregoing, the Department declines to adopt the Attorney General's seasonal rate design proposal for Rates R-1 and R-2. The Department addresses rate design for Rates R-1 and R-2 in the Rate-by-Rate section, below.

d. Inclining Block Rates

The Department finds that the Company's proposed flat rate structure for all rate classes is consistent with the rate design policy developed in recent base rate cases. D.P.U. 14-150, at 400; D.P.U. 13-90, at 250; D.P.U. 13-75, at 358-361; D.P.U. 12-25, at 468-469. As such, the Department approves the elimination of inclining block rates. Regarding the proper level to set the customer charge and volumetric rates for each residential and C&I rate class, the Department will make this determination on a rate class by rate class basis, balancing our rate design goals.

E. Low Income Discount

1. Introduction

a. Background

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low income customers comparable to the low income discount rate received off the total bill for rates in effect prior to March 1, 1998. See Expanding Low Income Customer

Protections and Assistance, D.P.U. 08-4, at 36 (2008). In the Company's last base rate proceeding, the Department made modifications to the application of the low income discount and established a low income discount of 25 percent applied to a Rate R-2 customer's total bill. D.P.U. 09-39, at 429-432.

The Company states that the current average low income monthly discount for a 500 kWh use customer is $30.04 or 28.8 percent (Exh. LI-1-5, at 2 (Supp.)). According to the Company, the monthly discount consists of the 25 percent total bill discount approved in D.P.U. 09-39 plus the discount from the Rate R-2 Energy Efficiency Reconciling Factor ("EERF") being less than that assessed to Rate R-1 customers (Exh. LI-1-5, at 2-3 (Supp.)).

b. Low Income Network's Recommendation

Pursuant to the second clause of § 141, [310] the Low Income Network initially recommended that the Department increase the average low income monthly discount from 28.8 percent to 35 percent (Exh. LI-JH-1, at 18). The Low Income Network's initial recommendation was based on the purported increase in costs associated with (1) renewable portfolio standard ("RPS") solar carve out; (2) RPS except solar carve out; (3) net metering recovery surcharge ("NMRS"); (4) long-term renewables contracts; (5) utility owned solar; and (6) Smart Grid pilots (Exhs. LI-JH-1, at 17-18; LI-1-5). According to the Low Income Network, these costs are related to the growth of on-site generation, and the increase in these costs has resulted in higher bills for low income customers (Exh. LI-JH-1, at 17-18, citing Exh. LI-1-5 (Supp.) & Att.). Therefore, the Low Income Network recommends an increase in the low

310 See n.300 above.

income discount to fully compensate low income customers for these increased costs (Exh. LI-JH-1, at 18).

Subsequently, on brief, the Low Income Network modified its recommendation for an increase of the low income discount from 25 percent to 33 percent (Low Income Brief at 23-24). The Low Income Network's revised calculation is based on the purported increase in costs associated only with (1) RPS solar carve out; and (2) NMRS (Low Income Brief at 23-24; Exhs. DPU-LI-1-5; WP-DPU-LI-4; WP-DPU-1-5). The Low Income Network acknowledges that only these two categories of costs are related to the growth of on-site generation (Low Income Brief at 23).

c. Company's Alternative Proposal

In response to the Low Income Network's proposal, the Company proposes to maintain the low income discount at its current level of 25 percent, but to exempt Rate R-2 customers from being charged for on-site generation costs that the Department concludes should be avoided by this customer group (Exh. NG-PP-Rebuttal-1, at 64). For instance, if the Department concludes that Rate R-2 customers should not pay for all or any part of the Company's cost of complying with the RPS that is a component of basic service rates, whether it be the solar carve-out and/or the non-solar carve out cost, the Company would exclude those costs from the RPS component of the low income basic service rates and allocate the estimate of those costs to all other Basic Service customers (Exh. NG-PP-Rebuttal-1, at 64).[311] Further, National Grid

[311] National Grid notes, however, that removing all or any part of the Company's cost of complying with the RPS from basic service rates for low income customers creates a lower basic service rate with which competitive suppliers would have to compete (Exh. NG-PP-Rebuttal-1, at 66). According to the Company, approximately 52 percent

states that with respect to net metering costs, the Company could alter the manner by which it recovers net metering credits paid for excess generation (Exh. NG-PP-Rebuttal-1, at 65). More specifically, in designing the NMRS factors, the Company proposes to exclude Rate R-2 in the allocation of the balance of the NMRS reconciliation and the amount would be recovered from all other customers (Exh. NG-PP-Rebuttal-1, at 65). Rate R-2 customers would therefore not be billed an NMRS (Exh. NG-PP-Rebuttal-1, at 65).

The Company's alternative proposal does not include the impact of displaced distribution revenue, which still would be recovered through the Company's RDM (Exh. NG-PP-Rebuttal-1, at 65). According to the Company, its alternative proposal is intended to simplify the application of the concept presented by the Low Income Network and has the added benefit of creating transparency in the amount of net metering costs recovered from non-low income customers (Exh. NG-PP-Rebuttal-1, at 65).

2. Positions of the Parties

a. The Low Income Network

The Low Income Network provided several reasons for its recommended increase to the low income discount. First, the Low Income Network argues that the scale of on-site generation[312] is now "substantial," with installed capacity from distributed generation on the Company's system exceeding 15 percent of the Company's peak load (Low Income Network

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of Rate R-2 customers currently receive electricity supply from a competitive supplier (Exh. NG-PP-Rebuttal-1, at 66).

312 The Low Income Network asserts that the Department should determine the meaning of the term "on-site generation," in the context of § 141 (Low Income Network Brief at 19). In this regard, the Low Income Network argues that "on-site generation" is used in a "common-sense manner" that encompasses only solar and other renewable energy production on the site of an end-use customer (Low Income Network Brief at 19 n.65).

Brief at 19, 20-21, citing Tr. 7, at 1003; RR-LI-2). Second, the Low Income Network contends that the scale of on-site generation has resulted in a six-percent increase in total bills for low income customers, thereby impacting the affordability of electric service for low income customers (Low Income Network Brief at 19).[313] In this regard, the Low Income Network claims that low income households already do not have sufficient income to meet the high cost of living in Massachusetts, and that the burden of paying for electricity is higher on low income households than other customers (Low Income Network Brief at 21-22). Thus, according to the Low Income Network, a six-percent increase in bills as a result of the scale of on-site generation is particularly onerous for low income customers (Low Income Network Brief at 22).

Third, the Low Income Network argues that the record supports an increase of the low income discount to 33 percent, as this level of discount takes into account costs associated with the RPS solar carve out and the NMRS and will represent a "fully compensating adjustment" to the low income discount rate (Low Income Network at 19, 22-23, citing Exhs. LI-JH-1, at 17-18; NG-PP-Rebuttal-1, at 55; LI-1-5; DPU-LI-1-3; DPU-LI-1-5; Tr. 7, at 1034-1036). According to the Low Income Network, the Company does not dispute the Low Income Network's calculations that produce a 33-percent discount for the low income discount (Low Income Network Brief at 24; Low Income Network Reply Brief at 6).

Finally, the Low Income Network argues that the Company's alternative proposal would violate § 141 because the method of providing a "fully compensating adjustment" would require low income customers on competitive supply to find a competitive supplier that is willing to offer a similar discount to that being offered by the Company (Low Income Network Brief

313 The Low Income Network states that this increase is inclusive of distribution charges and basic service or competitive supply rates (Low Income Brief at 19).

at 24-25). According to the Low Income Network, nothing in the record suggests that there are any such competitive suppliers (Low Income Network Brief at 25, citing Tr. 7, at 1040). Moreover, the Low Income Network claims that the Company fails to explain how its approach would address current impacts on affordability due to increased on-site generation (Low Income Reply Brief at 6). For all of these reasons, the Low Income Network asserts that the Department should reject the Company's proposal (Low Income Network Brief at 25).

b. Company

The Company argues that its rate design proposals are meant to avoid the current and future scale of energy efficiency and on-site generation from having any impact on the affordability of electricity for all customers, not just low income customers (Company Brief at 222-223). As a result, National Grid claims that its rate design proposals would obviate the need for what the Company considers a reconciling mechanism to address the "fully compensating adjustment" to the low income discount (Company Brief at 223).

Further, the Company submits that the Department is not required to order an electric distribution company to automatically increase its low income discount to compensate for the cost of on-site generation billed through rates to low income customers, but rather the Department should consider the magnitude of those costs on the affordability of electric service to this group of customers in light of such costs paid by all customers (Exh. NG-PP-Rebuttal-1, at 54).[314] Nevertheless, the Company acknowledges that the cost of on-site generation has

[314] With respect to the scale of on-site generation, the Company submits that if the Department is contemplating any "impact on affordability for low income customers" from "the scale of on-site generation," it should limit its analysis to consider on-site generation of any technology with a nameplate capacity of 60 kW or less (Company Brief at 222-223 at n.43).

increased over the past several years for all customers and may result in an additional burden to low income customers in being able to pay their electric bills. (Exh. NG-PP-Rebuttal-1, at 54-55).

The Company does not directly address the Low Income Network's revised recommendation to increase the low income discount to 33 percent. However, the Company notes that in order to arrive at the Low Income Network's original recommended discount of 35 percent, without changing the rates charged to Rate R-2 customers and in consideration of the EERF, the current 25 percent low income discount would need to be 31.6 percent (Exh. NG-RRP-Rebuttal-1, at 55).

Finally, National Grid expresses concern with the Low Income Network's proposal because, according to the Company, changing the discount percentage would require "an annual re-setting of the percentage reflecting changes in the cost of distributed generation reflected in rates charged to Rate R-2 customers, or else the value of the discount would either be diluted or more generous, depending upon how those costs change over time" (Exh. NG-PP-Rebuttal-1, at 56). The Company submits that in D.P.U. 09-39 the Company's recommendation for a clear discount calculated at 25 percent of the entire bill was intended to avoid resetting a discount rate based on a set of rates in effect at a specific point in time. (Exh. NG-PP-Rebuttal-1, at 56)

3. Analysis and Findings

Pursuant to § 141, a fully compensating adjustment shall be made to the low income discount where the scale of on-site generation would have an impact on affordability for low income customers. Based on our review of the record, the Department finds that on-site generation has grown with an increase in costs from associated incentives (i.e., the RPS solar

carve out and the NMRS). The increased costs of these incentives are included in customers' bills, including bills of low income customers (see Exhs. LI-JH-1, at 16-18; NG-PP-Rebutal-1, at 54-55; LI-1-5 (Supp.) & Atts.; Tr. 7, at 1034; RR-DPU-41 & Att.). Thus, low income customers have experienced an increase in bills as a result of the growth of on-site generation. Therefore, pursuant to § 141, the Department finds it appropriate to adjust the Company's low income discount.

As an initial matter, we decline to adopt National Grid's alternative proposal. The Company's proposal appears overly complex and would require competitive suppliers to modify the products that they offer to low income customers. We note that competitive suppliers have not had an opportunity for comment on such a modification.

We find that a fully compensating adjustment to the low income discount would include only the costs associated with the RPS solar carve out and the NMRS, as these costs are directly related to the growth of on-site generation. The Department calculates the incremental increase between 2010 and 2015 for RPS solar carve out and NMRS costs for low income customers to be $50.46, or $4.20 per month.[315] In order to fully compensate low income customers for this increase, as required by § 141, the Department directs the Company in its compliance filing to this Order to increase the low income discount such that the low income discount produces an additional $4.20 in discount for the average low income customer each month, based on all rates that are in effect when the Company's new distribution rates take effect. In order to calculate the

[315] The Department's calculation is based on information in the response to record request DPU-41 and the attachment to the record request. The $50.46 is derived by first multiplying the incremental difference in the two charges for each month by 500 kWh. Second, those monthly totals are summed to arrive at an annual figure. Finally, the annual figure is multiplied by 0.75 to account for the 25 percent low income discount.

revised low income discount, the Company shall base its calculation on a bill for an R-2 customer using 500 kWh per month to an undiscounted bill for that same customer.[316]

The adjusted low income discount will remain in effect until the Company's next base rate case, at which time the Department will determine whether further adjustment is warranted. The Department expects that in their respective next base rate proceedings, all electric distribution companies will file revised rate design proposals for low-income customers that comply with the standard set forth in § 141.

F. Farm Discount

1. Introduction

The farm discount is offered to customers who meet the eligibility requirements for being engaged in the business of agriculture or farming as defined in G.L. c. 128, § 1a. 220 C.M.R. § 11.04(6)(a)[317] (see also Exh. NG-PP-23, at 5 (proposed M.D.P.U. No. 1264)). These customers are eligible for an additional ten percent discount from their distribution service rates. 220 C.M.R. § 11.04(6)(a) (see also Exh. NG-PP-23, at 5 (proposed M.D.P.U. No. 1264)). For

316 As an illustrative example, the calculation that was provided in response to Record Request DPU-41 would be modified such that the value in column (a), row (1) would be $99.05, which is the undiscounted value in row (2) ($74.29/0.75).

317 Pursuant to 220 C.M.R. § 11.04(6)(a):

> Each [d]istribution [c]ompany shall provide [c]ustomers who meet the eligibility requirements for being engaged in the business of agriculture or farming, as defined in [G.L. c. 128, § 1A], a [ten percent] reduction in the rates to which such [c]ustomers would otherwise be subject. Each [d]istribution [c]ompany shall allocate to other rate classes, as part of a general rate case, the revenue deficiency resulting from the farm discount using an allocation method approved by the Department for the [d]istribution [c]ompany.

rate classes R-1, R-2, R-4, G-1, G-2, and the street lighting rate classes, the Company proposes to recover through the base rate for each rate class, the revenue shortfall in the test year attributable to each rate class from the farm discount (Exhs. NG-PP-1, at 53-54; NG-PP-13, at 1-4, 6; DPU-18-15). The proposed farm discount is included as an increase to revenue to be collected through the Company's proposed rate design and totals $572,833 (Exh. NG-PP-13, at 1-4, 6).[318] No party commented on the Company's proposal.

2. Analysis and Findings

The Department stated in Farm Discounts, D.T.E. 98-47, Letter Order at 6 (November 16, 1998), that gas distribution companies may defer costs associated with the implementation of the farm discount for consideration in a subsequent general base distribution rate case. See also D.P.U. 13-75, at 246. The Department has allowed amortization of the deferred farm discounts over periods consistent with the normalization period used to normalize rate case expense. D.P.U. 15-80/D.P.U. 15-81, at 240; D.P.U. 10-70, at 144; D.P.U. 09-30, at 263; D.T.E. 02-24/25, at 204-205.

The Department finds that the Company's proposed method of recovering the farm discount shortfall for each rate class is inconsistent with the Department's policy regarding farm discounts. The farm discount is a social benefit and as such it should be recovered from all customers. Therefore, the Department rejects the Company's proposal. Rather, we conclude that the Company may defer and recover the farm discount credit balance as an amortization in

318 For R-1/R-2: $343,797; for R-4: $244; for G-1: $101,730; for G-2: $125,092; and for street lighting: $1,970 (Exh. NG-PP-13, at 1-4, 6). Therefore, $343,797 + $244 + $101,730 + $125,092 + $1,970 = $572,833.

its next base rate case. D.P.U. 15-80/D.P.U. 15-81, at 240; D.P.U. 10-70, at 143-145; D.P.U. 09-30, at 262-263; D.T.E. 98-47, Letter Order at 6.

G. Rate-by-Rate Analysis

1. Introduction

The Department must determine, on a rate class by rate class basis, the proper level at which to set the customer charge and delivery charges for each rate class, based on a balancing of our rate design goals. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 193-194; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance its goals of fairness with its goal of continuity. For this balancing, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes.

2. Rate R-1 and Rate E

a. Company Proposal

Rate R-1 is available to all residential customers in private dwellings, individual apartments, churches, and farms (Exhs. NG-PP-1, at 51; NG-PP-23, at 4-5 (proposed M.D.P.U. Nos. 1264 (MECo) and 576 (Nantucket Electric))). National Grid proposes to increase the monthly customer charge from $4.00 to $5.50 per month for Rate R-1 in Phase I (Exh. NG-PP-1, at 52). The per kWh charge is calculated as the total class revenue requirement less the revenue recovered through the proposed customer charge and the farm discount credit, divided by the rate year kWh deliveries (Exhs. NG-PP-1, at 53; NG-PP-13, at 1).

Rate E is a closed rate only applicable to Nantucket Electric and is applicable to customers who had separately metered space heating, with the remainder of their electricity use metered and billed on Rate R-1 (Exh. NG-PP-1, at 51). Rate E was retained after the merger of New England Electric System and Nantucket Electric to ensure that customers with consumption billed on Rate E were not adversely affected by new distribution rates after the merger (Exh. NG-PP-1, at 51).

The current distribution rates and structure for Rates R-1 and E are identical, except for the cable facilities surcharge billed to all Nantucket Electric customers (Exh. NG-PP-1, at 51; M.D.P.U. No. 551). The Company proposes to terminate Rate E and move these customers onto Rate R-1. The Company also proposes to eliminate the inclining block volumetric charges for the Rate R-1 and Rate E classes, which the Department allowed above (Exh. NG-PP-1, at 50).

b. Analysis and Findings

Initially, the Department evaluates the Company's proposal to combine customers on Rate E with Rate R-1. No party objected to the Company's proposal. The Department finds this proposal to be reasonable because the cost to serve Rate E is similar to the cost to serve Rate R-1. Therefore, the Department directs the Company to terminate Rate E and transfer those customers taking service on Rate E to Rate R-1.

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the R-1 rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate R-1/E is $9.42 (Exhs. NG-PP-1, at 52; NG-PP-2(d) at 22; DPU-33-8, Att. at 22). Based on a review of the embedded costs and the bill impacts on customers, the

Department finds that a proposed monthly customer charge of $5.50 for Rate R-1 is reasonable. The Department directs the Company to set its volumetric charge for Rate R-1 so that the rate classes are charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the volumetric charges for Rate R-1 to collect the remaining class revenue requirement approved in this Order.

3. Rate R-2

a. Introduction

Rate R-2 is a subsidized rate that is available at single locations to all residential customers in private dwellings and individual apartments (Exhs. NG-PP-1, at 51; NG-PP-23, at 6-8, 70-72 (proposed M.D.P.U. Nos. 1265 (MECo) and 577 (Nantucket Electric))). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program ("LIHEAP") or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. NG-PP-23, at 6, 70 (proposed M.D.P.U. Nos. 1265 (MECo) and 577 (Nantucket Electric))). Rate design for Rate R-2 is the same as Rate R-1 for they are treated as one customer class group for rate design purposes, except customers on Rate R-2 currently receive a 25-percent discount off of their entire bill (Exh. NG-PP-1, at 52). The Company's RAAF, which operates outside of base rates on a reconciling basis, recovers the low-income discount and

arrears forgiven under the Company's Arrearage Management Program ("AMP") (Exh. NG-PP-1, at 47-48).

b. Position of the Parties

i. Low Income Network

The Low Income Network asserts that compared to the other electric utilities in the Commonwealth, the Company has a low rate of adding income-eligible customers onto its AMP (Low Income Network Brief at 2-6, citing Exhs. LI-ML-1, at 5-6; LI-2-2; Tr. 1, at 85 86; RR-LI-3; Low Income Network Reply Brief at 2). The Low Income Network argues that the Company should review its business practices to evaluate their affect AMP enrollment and file a report with the Department within six months of this Order outlining its future actions to improve AMP enrollment (Low Income Network Brief at 2-3, 6; Low Income Network Reply Brief at 2). Further, the Low Income Network maintains that the Company should continue to recover its AMP-related costs on a reconciling basis in the RAAF, consistent with recent Department orders regarding how AMP costs may be recovered (Low Income Network Brief at 3, 6-11, citing D.P.U. 15-80/D.P.U. 15-81, at 244-245; Investigation into Issues Affecting Low-Income Customers, D.P.U. 08-4, at 1-6, 40 (2008); Standards for Arrearage Management Programs for Low-income Consumers, D.T.E. 05-86, at 10-12 (2006); Low Income Network Reply Brief at 2-3). The Low Income Network contends that allowing AMP cost recovery on a reconciling basis is the best solution to meeting the Legislature's intent in requiring the Company to offer an AMP (Low Income Network Brief at 3, 6-11, citing Acts of 2005, c. 140, § 17(a); Low Income Network Reply Brief at 2-3). According to the Low Income Network, the

Company agrees with both of its recommendations (Low Income Network Brief at 3; Low Income Network Reply Brief at 2-3). The Company did not comment on these issues on brief.

c. Analysis and Findings

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the R-2 rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate R-2 is $9.42 (Exhs. NG-PP-1, at 52; NG-PP-2(d) at 22; DPU-33-8, Att. at 22). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that National Grid's proposed monthly customer charge of $5.50 for Rate R-2 is reasonable. The Department directs the Company to set its volumetric charge for Rate R-2 so that the rate class is charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the volumetric charges for Rate R-2 to collect the remaining class revenue requirement approved in this Order.

Moreover, the Department accepts the Low Income Network's recommendations regarding the AMP program (Exh. NG-PP-1, at 48-49; Tr. 1, at 85-86; Tr. 7, at 972-973). Therefore, the Department directs the Company to review its business practices that affect AMP enrollment and within six months of the date of this Order, file a report with the Department outlining its future actions to improve AMP enrollment. The Department allows the Company to continue AMP cost recovery through the Company's RAAF.

4. Rate R-4

a. Company Proposal

Rate R-4 is available to all residential customers in private dwellings, individual apartments, churches, and farms whose use exceeds 2,500 kWh per month for a twelve-month period and who opt for time-of use rates (Exhs. NG-PP-1, at 53; NG-PP-23, at 9-11, 73-75 (proposed M.D.P.U. Nos. 1266 (MECo) and 578 (Nantucket Electric))). The Company does not propose any changes to the Rate R-4 rate structure (Exh. NG-PP-1, at 53).

The Company proposes to decrease the monthly customer charge from $20.87 to $20.00 (Exhs. NG-PP-1, at 53; NG-PP-2(d), at 22). The also Company proposes that the peak and off-peak kWh charges recover the remaining revenue requirement and to set them to produce the same peak to off-peak ratio that is present in the current charges (Exh. NG-PP-1, at 53).

b. Analysis and Findings

Based on the Rate R-4 embedded costs and bill impacts, the Department finds that the Company's proposed customer charge and method for establishing the volumetric charges for Rate R-4, subject to our findings on the farm discount, satisfy continuity goals and produce bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the monthly customer charge at $20.00 and to set its volumetric charges to collect the remaining class revenue requirement approved in this Order using the peak to off-peak ratio that is present in the current charges, truncated at five decimal places.

5. Rate G-1

a. Company Proposal

Rate G-1 is available to C&I customers who have average use that does not exceed 10,000 kWh per month or 200 kW of demand (Exhs. NG-PP-1, at 54; NG-PP-23, at 12-14,

78-80(proposed M.D.P.U. Nos. 1267 (MECo) and 580 (Nantucket Electric))). The Company proposes to maintain the customer charge at $10.00 per month (Exhs. NG-PP-1, at 54). In addition, the Company proposes to maintain the customer charge for unmetered Rate G-1 service at $7.50 per month (Exh. NG-PP-13, at 3). The per kWh charge is calculated as the total class revenue requirement less the revenue recovered through the proposed customer charge, minimum bill provision and the farm discount credit, divided by the rate year kWh deliveries (Exhs. NG-PP-1, at 54; NG-PP-13, at 3). The Company also proposes to increase the minimum charge for G-1 service for all kVA over 25 kVA from $2.08 per kVA to $2.11 per kVA (Exh. NG-PP-13, at 3).

b. Analysis and Findings

Based on the Department's decision above not to accept the Company's tiered customer charge proposal, the Department directs the Company to design rates for the G-1 Rate class with a single monthly customer charge. According to the Company's allocated COSS, the embedded customer charge for Rate G-1 is $9.95 (Exhs. NG-PP-1, at 54; NG-PP-2(d) at 22). The Company also proposes to maintain the customer charge for unmetered Rate G-1 customers and a modest increase for the minimum charge for Rate G-1 service (Exhs. NG-PP-1, at 54; NG-PP-13, at 3). Based on a review of the embedded costs and the bill impacts on customers, the Department finds that the G-1 Rate, including the proposed changes to the customer charges for metered and unmetered service and the increase to the minimum charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department directs the Company to set its volumetric charge for Rate G-1 so that the rate class is charged based on a flat rate structure, truncated at five decimal places.

Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase. Therefore, the Department directs the Company to set the energy charge for Rate G-1 to collect the remaining class revenue requirement approved in this Order.

6. Rate G-2

a. Company Proposal

Rate G-2 is available to C&I and institutional customers who have average consumption greater than 10,000 kWh, but do not exceed 200 kW of demand (Exhs. NG-PP-1, at 55; NG-PP-23, at 15, 81 (proposed M.D.P.U. Nos. 1268 (MECo) and 581 (Nantucket Electric))). National Grid proposes to increase the customer charge for Rate G-2 customers from $16.56 to $25.00 per month (Exhs. NG-PP-1, at 57). Additionally, the Company proposes to increase the per-kW demand charge such that approximately 90 percent of the total revenue requirement is recovered through a combination of the customer charge and the demand charge (Exh. NG-PP-1, at 57). Further, National Grid proposes to increase the demand charge for Rate G-2 customers from $6.00 per kW to $8.50 per kW, and to collect the remainder of the rate class's revenue requirement through a uniform per-kWh charge (Exhs. NG-PP-1, at 57; NG-PP-18, at 7-12). Additionally, the Company proposes a high voltage delivery discount of $0.50 per kW for customers supplied at not less than 2,400 volts and not needing a line transformer (Exhs. NG-PP-1, at 57; NG-PP-14, at 1; NG-PP-13, at 4; NG-PP-23, at 16, 82 (proposed M.D.P.U. Nos. 1268 (MECo) and 581 (Nantucket Electric))).

b. Analysis and Findings

According to the Company's allocated COSS, the embedded customer charge for the G-2 Rate class is $31.83 per month (Exh. NG-PP-1, at 57). Based on a review of the bill impacts on customers, the Department finds that the G-2 Rate, designed with an increase in the monthly customer charge from $16.56 to $25.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department finds that the Company's proposed method for establishing the volumetric charge and demand charge[319] for Rate G-2, subject to our findings on the farm discount, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the demand charge at $8.50 per kW, and the volumetric charge to collect the remaining class revenue requirement approved in this Order, truncated at five decimal places.

7. Rate G-3

a. Company Proposal

Rate G-3 is available to C&I and institutional customers who have average use that exceeds 200 kW of demand (Exhs. NG-PP-1, at 57-58; NG-PP-23, at 18-20, 84-86 (proposed M.D.P.U. Nos.1269 (MECo) and 582 (Nantucket Electric))). The Company proposes to increase the customer charge for Rate G-3 customers from $200.00 to $223.00 per month (Exhs. NG-PP-1, at 57-58). The Company also proposes to eliminate the off-peak per kWh charge and collect the remaining class revenue requirement through only a demand charge (Exh. NG-PP-1, at 58). Further, National Grid proposes to increase the demand charge for Rate G-3 customers from $3.92 per kW to $7.00 per kW (Exhs. NG-PP-13, at 5; NG-PP-18, at 13).

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[319] The Department disallowed the Company's demand ratchet proposal for Rate G-2 in Section XIII.D.6.a above.

Additionally, the Company proposes a high voltage delivery discount of $0.50 per kW for customers supplied at not less than 2,400 volts and not needing a line transformer and a $6.91 per kW high voltage 115kV delivery discount (Exhs. NG-PP-1, at 57; NG-PP-13, at 5; NG-PP-14, at 1; NG-PP-23, at 19, 85 (proposed M.D.P.U. Nos. 1269 (MECo) and 582 (Nantucket Electric))).

b. Positions of the Parties

EFCA maintains that the Company did not provide evidence showing that a reduced volumetric rate is more efficient to promote energy conservation than the current rate (EFCA Brief at 17, citing Tr. 7, at 1,092). On the contrary, EFCA asserts that a zero per kWh rate sends a strong price signal that electricity conservation is not valuable by reducing incentives for energy efficiency, storage, and other technologies (EFCA Brief at 17, citing Exh. EFCA-MW/TW-1, at 53-54). Accordingly, EFCA recommends that the Department deny the Company's proposed volumetric rate design for Rate G-3 (EFCA Brief at 18).

Further, EFCA opposes the Company's proposed increase to the demand charge from $3.92 per kW to $7.00 per kW (EFCA Brief at 17). EFCA asserts that this $3.08 per kW increase violates the Department's rate design goal of continuity (EFCA Brief at 17). The Company did not specifically comment on the Rate G-3 on-peak volumetric rate or demand rate on brief.

c. Analysis and Findings

According to the Company's allocated COSS, the embedded customer charge for the G-3 Rate class is $218.54 per month (Exhs. NG-PP-1, at 57; NG-PP-2(d), at 22). Based on a review of the bill impacts on customers, the Department finds that the G-3 Rate, designed with an

increase in the monthly customer charge from $200.00 to $223.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable.

In the Department's decoupling Order, D.P.U. 07-50-A, we stated that decoupling revenues should be reconciled through the volumetric component of the distribution charge, because that rate design would provide customers with a greater incentive to reduce their energy consumption and would further the goal of promoting demand resources. D.P.U. 07-50-A at 59; see also, D.P.U. 10-70, at 332. Allowing the Company to reduce the volumetric distribution charge to zero in this proceeding is contrary to the Department's findings in D.P.U. 07-50-A and D.P.U. 10-70. A primary rate principle for the Department is to provide customers with the appropriate incentive to consume electricity as efficiently as possible. D.P.U. 10-70, at 332.

Although pricing distribution service on demand use may support the cost-to-serve principle, it is not the best rate structure to promote energy efficiency. D.P.U. 10-70, at 332. Therefore, it would be inappropriate to adopt the Company's proposal to recover all distribution costs through either customer charges, which are fixed, or demand charges, which are more difficult to avoid through energy efficiency. D.P.U. 10-70, at 332.

Another factor in the Department's decision is the current Rate G-3 volumetric distribution time-of-use rate. The Company's current Rate G-3 volumetric rate includes an on-peak volumetric distribution charge, thus providing a price signal to consume energy during off-peak periods (Exh. NG-PP-1, at 55).

Based on these considerations, the Department rejects the Company's proposal to reduce the on-peak volumetric distribution charge for Rate G-3 to zero. The Company is hereby directed to maintain the volumetric distribution charges at their current levels when designing

distribution rates in compliance with this Order. Given that the volumetric distribution charges will remain unchanged and the Department allowed the customer charge to increase to $223.00, the remaining increase in distribution rates for Rate G-3 should be applied to the demand charge component of distribution rates, truncated at two decimal places.[320] Therefore, all customers will continue to be charged a volumetric charge for distribution service.

The Department finds that this method for establishing the volumetric charges and demand charges for the G-3 Rate satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Company is directed to set the on-peak volumetric charge at $0.00753 per kWh, the off-peak volumetric charge at zero, and the demand charge to collect the remaining class revenue requirement approved in this Order (Exh. NG-PP-3(i) at 4).

8. Street Lighting

a. Introduction

National Grid currently has seven street lighting rates: (1) Rate S-1, for luminaires and supports owned and maintained by the Company; (2) Rate S-2, for customer-owned luminaires mounted on Company-owned distribution poles with maintenance provided by the Company; (3) Rate S-3 (Option A), for underground wiring installations with customer-owned foundations and Company-owned and -maintained luminaires and supports; (4) Rate S-3 (Option B), for underground wiring installations with customer-owned luminaires and supports, with limited maintenance by the Company; (5) Rate S-5, for equipment owned and maintained by customers; (6) Rate S-6, for Company-owned decorative street and area lighting, available to municipal and other governmental customers for municipally owned or accepted roadways; and (7) Rate S-20,

320 The Department disallowed the Company's demand ratchet proposal for Rate G-3 in Section XIII.D.6.a above.

for luminaires and supports owned and maintained by the Company, which is available to any customer on the S-1 rate that agreed to convert all existing incandescent and mercury vapor source lights to sodium-vapor source lights (Exhs. NG-PP-1, at 58-59; NG-JEW-1, at 3-5; DPU-1-1). Rates S-2 and S-3 are closed to new customers (Exh. NG-PP-1, at 58-59).

b. Company Proposals

In its initial filing, the Company proposed to increase the rates for each luminaire and support in Rates S-1, S-2, S-3, and S-6 by 4.41 percent (Exhs. NG-PP-1, at 59; NG-PP-13, at 7-9). The 4.41 percent increase represents the overall street lighting increase necessary to achieve the level of revenue assigned in the revenue allocation process, after calculating the revenue achieved from Rate S-5 (Exh. NG-PP-1, at 59). For the Rate S-5 per kWh rate, the Company divided the cost associated with the support of the distribution system by the total street lighting kWh deliveries (Exhs. NG-PP-1, at 60; NG-PP-15; WP NG-PP-6).

As noted above, National Grid proposes revisions to Rate S-1 for the purpose of offering a Company-owned LED lighting service option to Rate S-1 customers (Exh. NG-JEW-1, at 5). National Grid's proposal allows for customer selection of LED luminaires that are owned and maintained by the Company (Exh. NG-JEW-1, at 5). The Company explained that the LED luminaires would replace existing incandescent, mercury-vapor, and high pressure sodium lighting equipment installed at existing locations, at the customer's request, or could be installed in new locations (Exh. NG-JEW-1, at 5-6).

Under the proposal, when a customer requests the installation of LED lighting equipment, National Grid will require the customer to pay the unamortized balance of the original installation costs, plus cost of removal less salvage value, for the existing streetlights, in excess

of one percent of the total streetlights on the customer's account (Exh. NG-JEW-1, at 10-11). The Company proposes to offer four different types of roadway LED fixtures and one post-top LED fixture (Exh. NG-JEW-1, at 6). The proposed LED fixtures range from 30 watts to 275 watts and provide comparable illumination to existing lighting fixtures installed throughout the Company's service area (Exh. NG-JEW-1, at 6). Additionally, National Grid proposes a cap on the number of LED fixtures that it will replace of ten percent per year of the total quantity of active and inactive street and area lighting fixtures per customer account, if that customer is considered a municipal, governmental authority, or public entity (Exh. NG-JEW-1, at 9). Typically, a customer's request to exchange a lighting fixture is incorporated into the Company's work schedules (Exh. NG-JEW-1, at 9). However, National Grid expresses concern with managing operational priorities and ensuring safe and reliable electric service while meeting customer demand for LED fixture installations (Exh. NG-JEW-1, at 9).

Finally, the Company proposed to cancel Rate S-20 and transfer all customers to Rate S-1, effective with the implementation of new rates resulting from this rate case (Exh. NG-PP-1, at 61). Rate S-20 provided customers with an incentive to convert older, less energy efficient technology of incandescent and mercury vapor lamps to more efficient sodium vapor lamps by offering a lower rate to the customer while the Company performed the conversion (Exh. NG-PP-1, at 61). After the Company completes the conversion work, the customer was transferred back to Rate S-1 (Exh. NG-PP-1, at 61). National Grid has converted all of the customers that took advantage of the conversion incentive, though some remain to be transferred to Rate S-1 (Exhs. NG-PP-1, at 61; NG-PP-3(i) at 6; DPU-15-23).

c. Positions of the Parties

DOER argues that the Department should approve the Company's proposed S-1 tariff for the LED lighting option with certain additional revisions (DOER Brief at 2-3). Specifically, DOER contends that the Company should offer its municipal street-lighting customers a 20-watt LED fixture as an economically beneficial replacement for a 50-watt high-pressure sodium ("HPS") fixture (DOER Brief at 3). Further, DOER recommends that the Company offer a 30-watt LED fixture to replace a 70-watt HPS fixture (DOER Brief at 3). DOER claims that these modifications are necessary to encourage municipal customers to convert to the more efficient LED lighting technology (DOER Brief at 3). According to DOER, the Company has agreed to these S-1 tariff revisions (DOER Brief at 3, citing Tr. 6, 808-809; RR-DOER-3).

Additionally, DOER recommends that the Department remove the ten-percent annual cap on LED lighting conversions (DOER Brief at 3). According to DOER, National Grid did not provide any evidentiary support for the ten-percent annual cap or any alternative amount (DOER Brief at 3-4). Therefore, DOER asserts that the ten-percent cap is arbitrary and unsubstantiated (DOER Brief at 4). Instead, DOER recommends that the Company prioritize LED lighting conversions in the context of other customer service priorities, capital investment plans, and storage costs (DOER Brief at 4). Neither National Grid nor any other party commented on the Rate S-1 and S-20 tariff proposals on brief.

d. Analysis and Findings

National Grid has proposed a variety of changes to its street lighting service. The Department has examined the proposed rate design for the street lighting rate classes S-1, S-2, S-3, S-5, and S-6 (Exh. NG-PP-23, at 21-65, and 87-132 (proposed M.D.P.U. Nos. 1270 through

1274 (MECo); and 583 through 587 (Nantucket Electric))). The Department finds that the proposed rate design for the street lighting rate classes satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs National Grid in the compliance filing to compute the street light charges using the method proposed by the Company, subject to our findings on the farm discount, and the increase from the allocation process and revenue requirement for the street light class approved in this Order.

Regarding DOER's recommendations that the Company offer certain LED fixtures to replace existing HPS luminaries, the Company has agreed to accept DOER's recommendation to offer a 20-watt LED fixture that is an economically beneficial replacement for a 50-watt HPS fixture (RR-DOER-3, Att. 2). Further, we note that in its initial filing, the Company already offers a 30-watt LED fixture as a comparable luminaire to the 70-watt HPS (see Exhs. NG-PP-16, at 3; NG-PP-23, at 24 and 90 (proposed M.D.P.U. Nos. 1270, Sheet 4 (MECo); 583, Sheet 4 (Nantucket Electric))).

National Grid corrected its calculations used to determine its proposed LED lighting rates from its initial filing (RR-DPU-21; RR-DOER-3 & Atts). The Department has reviewed National Grid's method of calculating the S-1 rate for the LED lighting option, and finds that it is cost-based and, therefore, reasonable (see RR-DOER-3, Atts.). Therefore, the Department directs the Company in its compliance filing to compute the rate for the LED lighting option for Rate S-1 using the revised method proposed by National Grid, a revised carrying charge calculation pursuant to our findings in Sections VII, VIII.G, and XII, and the allocation process and revenue requirement for the Rate S-5 approved in this Order.

Next, with respect to the Company's proposed cap on fixture replacements, the Company proposed the following provision in its S-1 tariff:

> The Company shall use its best efforts to replace existing lights with LED within a reasonable length of time after receipt of the written notice requesting such replacement. Depending upon the number of street and area lighting facilities to be replaced with LED lights and the availability of the Company's crews, the Company may limit the quantity of LED replacements to 10 [percent] per account per calendar year to allow for efficient operations. The Company reserves the right to be flexible in responding to the Customer's request. However, the Company shall complete all requests according to a mutually accepted schedule between the Customer and the Company upon receipt of written notice.

(Exh. NG-PP-23, at 24, 90 (proposed M.D.P.U. Nos. 1270, Sheet 4 (MECo); and 583, Sheet 4 (Nantucket Electric))).

As noted above, DOER recommends that the Department remove the ten-percent annual cap on LED lighting conversions from the proposed tariff (DOER Brief at 3). The Department agrees with this recommendation. The Company's need to limit replacements at ten percent is speculative and premature (see, e.g., Exhs. DOER-1-3, at 2; DOER-1-7). The Company is unable to provide an estimate regarding the quantity of street lighting fixtures that were replaced for past municipal inquiries into efficient lighting (Exh. DPU-1-2). Additionally, National Grid has previously implemented similar street lighting activities in a way that allowed the Company to work these activities into its existing workload and resource plans (Exh. DOER-1-7). Therefore, the Department directs National Grid to strike the following sentence from its proposed tariff: "Depending upon the number of street and area lighting facilities to be replaced with LED lights and the availability of the Company's crews, the Company may limit the

quantity of LED replacements to 10 [percent] per account per calendar year to allow for efficient operations."[321]

Finally, we note that National Grid has converted all customers that took advantage of the Rate S-20 incentive (Exh. NG-PP-1, at 61). Therefore, the Department finds that the Company's proposal to discontinue Rate S-20 is reasonable. Accordingly, the Department approves the cancellation of Rate S-20 and the transfer of all customers who are currently billed on Rate S-20 to Rate S-1.

XIV. PROPOSED FEES AND TARIFF CHANGES

A. Access Fee for Stand-Alone Distributed Generation Facilities

1. Introduction

a. Background

Stand-alone DG facilities are those that are directly connected to the distribution system and have no associated on-site load (Exh. NG-PP-1, at 70). The Company states that because stand-alone DG facilities generally have no on-site load, the facilities are eligible for and typically are assigned to Rate G-1, which is available for any C&I customer who uses less than 10,000 kWh per month (Exh. NG-PP-1, at 73). Customers who take service under the Rate G-1 class, including stand-alone DG facilities, pay a monthly customer charge of $10.00, plus associated taxes (Exh. NG-PP-1, at 73; Tr. 7, at 1124). In addition to the customer charge, all stand-alone DG facilities that apply for interconnection to the Company's distribution system

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321 Should the actual level of replacement of streetlights to LED lights be such that the Company's crews are unable to complete in a timely fashion, then the Company may petition the Department and request an appropriate limit on the pace of replacement. The Department expects that the petition would be supported by sufficient evidence showing that such a limit is warranted.

may incur the costs that are necessary to expand or upgrade the distribution system (i.e., "system modifications") in order for the facility to safely interconnect without adversely affecting the reliability or the distribution system (Exh. NECEC-1-12).[322]

Apart from the customer charge, associated taxes, and any system modification costs, stand-alone DG facilities do not pay any other costs for use of the Company's distribution system (Exhs. NG-PP-1, at 73; NECEC-1-12). In particular, the Company states that interconnection costs for stand-alone DG facilities do not include the costs associated with: (1) the recovery of ongoing O&M and the replacement of interconnection equipment;[323] (2) energy and transmission and distribution ("T&D") service, as well as, non-T&D service for continued use of the electric power system;[324] (3) short term and long term investments to support enhanced quantities of DG on the electric power system;[325] and (4) the interval metering required for the stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3;

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322 See also, Standards for Interconnection of Distributed Generation Tariff, M.D.P.U. No. 1248.

323 The Company identifies the following O&M expenses it incurs to provide service to a stand-alone DG facility: (1) ISO-NE communications and settlement; (2) allocating net metering credits; (3) resolving billing issues; (4) municipal property taxes; (5) repair and replacement of damaged equipment; and (6) vegetation management (Exhs. DPU-21-3, at 2; LI-1-10).

324 The electric power system includes both the distribution system and the transmission system.

325 National Grid states that it has made relatively low-cost investments to date as a result of low levels of DG penetration, but over the long term the Company expects to make higher cost investments to handle two-way power flow between customer DG implementations and the electric distribution system (Exh. EFCA-1-9; Tr. 7, at 1142-1144).

AG-27-8; LI-1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NECEC-1-13; NECEC-1-19).[326]

b. Company Proposal

National Grid proposes to assess new stand-alone DG facilities that take service under its Rate G-1 a monthly access service fee ("Access Fee") (Exh. NG-PP-1, at 70, 73). The proposed Access Fee is intended to recover from the stand-alone DG facilities the costs beyond those recovered from the customer charge, associated taxes, and payments for system modification that are attributable to interconnection with the distribution system (Exhs. NG-PP-1 at 74; AG-27-8). The Company proposes an Access Fee charge of $7.00 per kW-month for customers connected at the primary voltage level and $8.50 per kW-month for customers connected at the secondary voltage level (Exh. DPU-12-4).[327] The Company's proposed Access Fee charges are identical to the proposed demand charges for Rate G-3 (primary voltage fee) and Rate G-2 (secondary voltage fee) (Exh. DPU-12-4).

The Company proposes to calculate the monthly Access Fee by multiplying the applicable Access Fee charge by the nameplate capacity of the stand-alone DG facility, adjusted for its expected availability at peak loading conditions, which the Company refers to as the

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326 To comply with ISO-NE load reporting requirements, National Grid must install for these stand-alone DG facilities a complex and expensive interval meter that typically is installed on larger C&I customers. The cost of this type of meter is not included in the Rate G-1 revenue requirement (Exh. NG-PP-1 at 74). The Company provides a cost estimate of $1,690 to install an interval meter for a stand-alone DG facility (Exh. NECEC-1-19 & Att.).

327 Under the Company's proposed Access Fee charge, voltage greater than or equal to 1,000 volts would qualify as a primary voltage; voltage less than 1,000 volts would qualify as secondary voltage (Exhs. NG-PP-1, at 71; DPU-12-4).

"capacity availability factor" (Exhs. NG-PP-1, at 70-72; DPU-12-4).[328,329] National Grid proposes that the Access Fee will apply to stand-alone DG facilities applying for interconnection service after the effective date of its proposed Phase I rates, however, the Company will not begin billing the proposed Access Fee until its proposed Phase II rates go in effect, which is expected to be no earlier than April 2017 (Exhs. NG-PP-1, at 72-73; NG-PP-Rebuttal-1, at 48; DPU-12-5) (see Section XIII.D.3 above). Finally, the Company proposes that all revenues it bills for the Access Fee will be credited to customers through the RDM (Exh. DPU-32-30).

c. Chapter 164, § 139(j)

On April 11, 2016, Governor Baker signed into law Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy ("Solar Act"). Among other things, the Solar Act amended General Laws Chapter 164 by adding Section 139(j) ("§ 139(j)"), which provides:

> (j) Distribution companies may submit to the department proposals for a monthly minimum reliability contribution to be included on electric bills for distribution utility accounts that receive Class I, Class II, Class III, or market net metering credits pursuant to this section, subject to the review and approval of the department. Any such minimum contributions shall ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system. Proposals shall be filed with the department in: (i) the distribution company's base distribution rate proceeding; or (ii) a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes. The department may

328 The Company defines the capacity availability factor as the peak load in kilowatts that a turbine or solar array needs from the distribution system to monetize its output (Tr. 7, at 1170).

329 The Company proposes the following capacity availability factors for stand-alone DG facilities: solar- 40 percent; wind – 30 percent; anaerobic digestion – 50 percent; and hydroelectric – 10 percent (Exhs. NG-PP-1 at 72, DPU-12-4). Thus, for example, a monthly access fee for a 1-MW stand-alone DG facility connected at the primary voltage level would incur a $2800 monthly access fee. The calculation would be $7.00 Access Fee charge x 1000-kW nameplate capacity x 40 percent solar capacity availability factor (Exh. DPU-12-4).

> approve a monthly minimum reliability contribution that: (i) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (ii) does not excessively burden ratepayers; (iii) does not unreasonably inhibit the development of Class I, Class II, Class III facilities; and (iv) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance and safety of the electric distribution system.
>
> The department may only approve a proposal for a monthly minimum reliability contribution after the aggregate nameplate capacity of installed solar generating facilities in the commonwealth is equal to or greater than 1,600 megawatts. The department shall conduct a full adjudicatory proceeding when reviewing proposals for a monthly minimum reliability contribution, which shall include at least [one] public hearing and an opportunity for public comment.

See also 220 C.M.R. § 18.10.

National Grid submits that the proposed Access Fee meets the purpose of § 139(j), as it is intended as a monthly contribution from stand-alone DG customers to ensure that these customers contribute toward the fixed costs of ensuring the reliability, proper maintenance, and safety of the electric distribution system (Exh. NG-PP-Rebuttal-1, at 47). Further, the Company submits that while § 139(j) provides for a monthly minimum reliability contribution ("MMRC"), it does not expressly curtail or prohibit the Department, acting pursuant to its plenary ratemaking authority, from approving the proposed Access Fee in another manner (such as on an earlier timeframe) (Exh. NG-PP-Rebuttal-1, at 47). Moreover, National Grid contends that assuming the requirements of the statute are applicable to its proposed Access Fee, these requirements have been satisfied because its proposed Access Fee: (1) equitably allocates fixed costs not caused by volumetric consumption; (2) does not excessively burden its customers; (3) will not unreasonably inhibit the development of DG facilities; and (4) is dedicated to offsetting the Company's reasonable and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the distribution system (Exh. NG-PP-Rebuttal-1, at 47). Finally, the

Company notes that the implementation of its proposed Access Fee is expected to coincide with the expected date that the aggregate nameplate capacity of installed solar generating facilities in the Commonwealth is equal to or greater than 1,600 megawatts, as described in § 139(j) (Exh. NG-PP-Rebuttal-1, at 47).

2. Positions of the Parties

a. Intervenors, Limited Intervenors, and Limited Participants

i. Introduction

Eversource supports the Company's proposed Access Fee. According to Eversource, the proposed Access Fee is appropriate because: (1) the record in this case demonstrates that stand-alone DG facilities impose costs on the distribution system similar to the costs imposed by medium- and high-use commercial customers yet these stand-alone DG facilities pay the same customer charge as low-use commercial customers; (2) the Company does not recover the full costs to serve stand-alone DG facilities; and (3) the Company's other customers cross-subsidize the stand-alone DG customers (Eversource Brief at 2-3). Further, Eversource asserts that the Department has the ratemaking authority to approve the proposed Access Fee, which Eversource contends complies with the MMRC provision of the Solar Act (Eversource Brief at 2-3).

On the other hand, the Acadia Center, EFCA, NECEC, and Vote Solar (collectively as "Limited Intervenors"), along with the Attorney General, DOER, and PowerOptions, all oppose the Company's proposed Access Fee. Their arguments essentially are three-fold: (1) there is insufficient evidentiary support for the proposed Access Fee; (2) the proposed Access Fee is not a valid substitute for the MMRC; and (3) the proposed Access Fee is inconsistent with the Department's rate design goals. These arguments are discussed in further detail below.

ii. Evidentiary Support for the Proposed Access Fee

Several commenters argue that the Company bears the burden of proving the propriety of any of its proposed rate increases, including documenting and quantifying with record evidence the distribution costs it claims that stand-alone DG customers are shifting to other customers (Acadia Center Reply Brief at 3; DOER Reply Brief at 5; EFCA Reply Brief at 3). In this regard, the Limited Intervenors and the Attorney General contend that the Company did not provide record evidence to show that the Access Fee is required to recover costs that the stand-alone DG facilities impose on the distribution system, or that the Access Fee is set at an appropriate level, or that, absent an Access Fee, there would be a cost shift from stand-alone DG customers to non-DG customers (Attorney General Brief at 145-146; Acadia Center Brief at 15-16; EFCA Brief at 9-10; NECEC Brief at 37; Vote Solar Brief at 20; Vote Solar Reply Brief at 10).

In particular, the Attorney General contends that National Grid does not provide sufficient information for the Department to properly design or evaluate the proposed Access Fee, as the Company fails to include any analysis of (1) current costs for stand-alone DG facilities' use of the distribution system, or (2) incremental distribution system costs for upgrades to accommodate additional stand-alone DG facilities (Attorney General Brief at 145-146). Further, Acadia Center argues that the Company has not shown that the current rate design is unfair where stand-alone DG customers pay their marginal cost and non-DG pay reliability costs, safety costs, and other embedded costs (Acadia Center Brief at 15-16). EFCA also asserts that the Company provided no evidence that DG customers are shifting costs to non-DG customers (EFCA Brief at 9-10). Further, NECEC argues that National Grid provided no analysis to show

the actual cost to serve stand-alone DG facilities, but rather the Company merely asserts that such costs exist because of the expanded adoption of DG resources (NECEC Brief at 37). Finally, Vote Solar maintains that as the Company does not quantify the costs that stand-alone DG customers impose on the distribution system, consequently the Company does not know if these customers contribute more or less revenue than is the cost to serve (Vote Solar Brief at 20; Vote Solar Reply Brief at 10).

Next, DOER and several of the Limited Intervenors argue that the Company provided no evidence to prove that stand-alone DG facilities impose the same costs on the distribution system as are imposed by a Rate G-3 or Rate G-2 customer (DOER Brief at 9-10; EFCA Brief at 22-25; EFCA Reply Brief at 17-18, 21; NECEC Brief at 33-36; NECEC Reply Brief at 2; Vote Solar Brief at 21; Vote Solar Reply Brief at 10). DOER and the Limited Intervenors also contend that the Company's rationale, that the Access Fee is appropriate because the distribution system must be sized to accommodate maximum demand whether inflow or outflow of electricity, is flawed because: (1) diversity of demand ensures that any individual customer's use of the distribution system is not a significant driver for sizing upstream portions of the system; (2) stand-alone DG resources pay for necessary system upgrades in their vicinity through the interconnection process; (3) backflow,[330] from the two-way power flows, is not a significant problem for the

[330] The Company notes that backflow (or "backfeed") occurs on the distribution system when power on a radial distribution system that is designed to flow from substations out to customers flows back into the substation from DG located on the feeder (Tr. 7, at 1007).

Company's distribution system;[331] and (4) electricity produced by stand-alone DG facilities during peak demand time reduces demand on the upstream portion of the distribution system (DOER Brief at 9-10; Acadia Center Brief at 15-16; EFCA Brief at 11, 22-25; EFCA Reply Brief at 17-18, 21; NECEC Brief at 33-36; NECEC Reply Brief at 2; Vote Solar Brief at 21; Vote Solar Reply Brief at 10).

In addition, the Attorney General and EFCA argue that the Company failed to justify certain cost categories that it uses to substantiate the need for its proposed Access Fee (Attorney General Brief at 146; EFCA Reply Brief at 5). In particular, the Attorney General asserts that the Company failed to justify such costs as on-going customer service aspects and the need for further investments to its distribution system (Attorney General Brief at 146). EFCA posits that the Company only quantifies costs for two additional full-time employees and future O&M expenses as costs that it presently does not recover in stand-alone DG customers' interconnection fees (Exh. LI 1-21; EFCA Brief at 9, n.27; EFCA Reply Brief at 5; Tr. 7, at 1067, 1070-71).

The Attorney General, DOER and NECEC also raise issues regarding the sufficiency of the evidence regarding the capacity availability factors. According to the Attorney General and NECEC, the Company's capacity availability factors are flawed, violate the principles of cost causation, and lacks transparency (Attorney General Brief at 142-145; NECEC Reply Brief at 7-8). In this regard, the Attorney General and NECEC maintain that the Access Fee calculation does not recognize the load reducing benefits of DG, which reduce the Company's distribution system costs when the stand-alone DG facilities generate power during peak hours;

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331 The Attorney General maintains that a number of the Company's feeders are experiencing back flow conditions (Attorney General Brief at 145 n.51, citing Exhs. AG- 27-14, Att.; NECEC-1-16, Att. (Supp.); RR-AG-24).

rather, they contend that the Company designed the Access Fee calculation to increase if the load reducing benefits increase from a higher capacity availability factor (Attorney General Brief at 142-143; NECEC Reply Brief at 8).[332] According to the Attorney General, an Access Fee proposal aligned with cost-causation should increase where the cost-reducing benefits of a stand-alone DG facility decreases (Attorney General Brief at 142-143). In addition, the Attorney General contends that using a system-wide availability factor to calculate the Access Fee does not accurately track cost causation for all DG technology types, because peak times vary by the customer mix on a given feeder (Attorney General Brief at 144). Further, the Attorney General claims that the Company did not provide adequate support for using a 40-percent solar capacity availability for the Access Fee calculation (Attorney General Brief at 144-145). Finally, DOER argues that the Company improperly used a limited sample size of wind, anaerobic digestion, and hydroelectric facilities to determine the proposed capacity availability factors (DOER Brief at 10).

The Attorney General and several Limited Intervenors also argue that in, addition to the lack of evidence to support the costs and design of the proposed Access Fee, National Grid failed to provide complete data on the benefits and costs associated with DG in general, and, without this information, the Company cannot fully understand the impact of increasing DG penetration on its distribution system and determine whether DG customers will be charged the appropriate

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332 The Attorney General contends that the Access Fee as proposed would increase if a stand-alone DG facility provides more generation into the Company's distribution system (Access Fee = voltage charge x nameplate capacity x capacity availability factor) (Attorney General Brief at 142-143, citing Tr. 7, at 1148-1153). The Attorney General explains that this result is counterintuitive. If generation from these stand-alone DG facilities increases during periods when the Company experiences peak load condition, the stand-alone DG facilities will decrease the system peak and, therefore, decrease the Company's overall system costs (Attorney General Brief at 142-143).

cost of service (i.e., Access Fee) (Attorney General Brief at 145-146; Acadia Center Brief at 10-12; EFCA Brief at 11; EFCA Reply Brief at 4-5, 6-7, 20; NECEC Brief at 46). According to the Attorney General and these Limited Intervenors, further study of costs and benefits is necessary to fairly assess and assign incremental costs that DG customers impose on the distribution system (Attorney General Brief at 145-147; Acadia Center Brief at 10-12; EFCA Brief at 10-11; EFCA Reply Brief at 6-7, 20; NECEC Brief at 46). Further, Acadia Center and EFCA note that National Grid is participating in regulatory proceedings in New York,[333] and Rhode Island,[334] that seek to identify and quantify the benefits and costs of DG, so it is reasonable to expect that the Company would do the same in the instant proceeding as part of its Access Fee proposal (Acadia Reply Brief at 3-4; EFCA Reply Brief at 6-7). Moreover, Acadia Center contends that the value of DG resources should be a part of the next evolutionary phase in economic analysis of ratemaking as it is a key element in analysis of cost shifts (Acadia Center Brief at 10-11). Further, the Attorney General argues that a properly designed access fee, including costs and benefits, would take into account any incremental distribution system costs

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333 Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources at the New York Public Service Commission (Acadia Center Reply Brief at 3, n.9). EFCA and Acadia Center remark that National Grid is a signatory to the New York Progress Partnership, a New York REV (Revolutionizing the Energy Vision) regulatory proceeding that seeks to value DG and distributed energy resources in which utilities conduct a benefit-cost analysis to quantify the value and explore how to incent DG facilities to cite facilities in locations that will maximize their benefit to the grid (Acadia Center Reply Brief at 3-4; EFCA Reply Brief at 7, citing Exh. EFCA-CG-Rebuttal-1, at 12).

334 Docket 4600, Investigation into the Changing Distribution System and the Modernization of Rates in Light of the Changing Distribution System, at the Rhode Island Public Utilities Commission (Acadia Center Reply Brief at 3 n.9).

driven by upgrades needed to accommodate DG, which depends on whether the location of the DG is reducing or adding feeder load (Attorney General Brief at 145).

Several of the Limited Intervenors reject the Company's claim that there is little evidence of locational capacity benefits from DG on its system; they argue that the record includes evidence that demonstrates locational benefits (Acadia Center Reply Brief at 10; EFCA Reply Brief at 6-7; NECEC Brief at 39-41). For instance, NECEC argues that stand-alone DG facilities on the Company's distribution system reduced maximum circuit loads by ten percent on those circuits serving such stand-alone DG facilities, which then provided additional capacity to serve other customers; and in Massachusetts, an average distributed generation resource provides 36 percent of its nameplate capacity during times of peak feeder loading (NECEC Brief at 40-41). EFCA maintains that the Company recognized the load relief provided by DG projects by incorporating solar capacity on its system into its load forecasting, and that the Company conceded that the output from a stand-alone DG customer reduces the upstream load on the distribution system (EFCA Reply Brief at 20; EFCA Brief at 11; Tr. 5, at 737). Further, EFCA rejects the Company's claim that it is double-counting to quantify distribution system benefits both from solar in solar renewable energy credits ("SRECs")[335] and from net metering incentives (EFCA Reply Brief at 8). EFCA asserts that the Company's argument that SRECs are a proxy for the total value that distributed resources provide to the grid is erroneous as distributed

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335 According to EFCA, SRECs value is based primarily on the targets that "state policy-makers" assign to supply and demand as a means of incenting carbon reductions, which is independent of the total value of distributed generation on the Company's distribution system (EFCA Reply Brief at 8). Further, EFCA contends that SRECs are environmental commodities that represent the environmental attributes from renewable energy resources and should be taken into account (EFCA Reply Brief at 8).

resources provide more than environmental benefits, and that the Company does not present any evidence of the value of SRECs (EFCA Reply Brief at 8).

iii. MMRC and the Solar Act

The Attorney General and NECEC argue that, as a threshold procedural matter, the Department cannot approve the Company's proposed Access Fee as a MMRC because Massachusetts has not yet reached the 1,600-megawatt aggregate nameplate capacity of installed solar generating facilities, and will likely not reach this threshold until 2017 (Attorney General Brief at 140-141; NECEC Brief at 49, citing § 139(j)).

NECEC and Vote Solar contend that National Grid's proposed Access Fee does not meet the requirements of § 139(j) because the Company has failed to demonstrate that the proposed Access Fee: (1) equitably allocates the fixed costs of the electric distribution system, as the Company has not conducted any analysis to equate the demand-related costs to serve Rate G-2 and Rate G-3 customers to that of stand-alone DG facilities; (2) will not excessively burden ratepayers as it does not quantify costs attributed to stand-alone DG facilities; (3) will not unreasonably inhibit the development of Class I, Class II and Class III net metering facilities;[336] and (4) will offset reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the distribution system (NECEC Brief at 48-51; Vote Solar Brief at 23-25; Vote Solar Reply Brief at 13-18).

Acadia Center also argues that the proposed Access Fee contradicts the stated policy goals of the Solar Act, which Acadia Center claims are to support community-shared and low income solar facilities, and that the proposal may encourage more expensive on-site solar

336 The three classes of net metering facilities are defined in 220 C.M.R. § 18.02.

projects rather than more cost-effective stand-alone DG facilities (Acadia Center Brief at 16, citing, Exh. AC-AA-Rebuttal-1, at 7; Acadia Center Reply Brief at 10). Further, Acadia Center, EFCA, and Vote Solar contend that the Department should reject the Company's proposed Access Fee as unnecessary because the Solar Act provides for a 40-percent reduction in the market net metering credits to alleviate any purported cost shifts from DG customers to non-DG customers (Acadia Center Brief at 17; EFCA Reply Brief at 5-6; Vote Solar Brief at 25). Further, EFCA questions whether the Access Fee is legal under the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[337] as EFCA alleges that the Company's proposal constitutes a fee on qualifying facilities that could make the cost to operate a qualifying facility economically prohibitive (EFCA Brief at 26).

The Attorney General and PowerOptions recommend that the Department open a generic proceeding to consider creating a standardized MMRC or Access Fee applicable to stand-alone DG facilities, so that all potential stakeholder can participate in the process (Attorney General Brief at 147-148; PowerOptions Reply Brief at 8-9). According to the Attorney General and PowerOptions, a general proceeding would allow the Department to decide many of the issues relevant to the design of an Access Fee before the 1600-MW threshold is met and to promote administrative efficiency for future base rate proceedings (Attorney General Brief at 147-148; PowerOptions Reply Brief at 8-9).

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337 PURPA, Pub. L. 95–617, 92 Stat. 3117 was passed as part of the National Energy Act of 1978. EFCA notes that PURPA is meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply) (EFCA Brief at 26 n.87).

iv. Rate Design Issues

NECEC notes that it supports re-evaluating rate design so that rates send accurate price signals that allow customers to optimize energy consumption and encourage the deployment of advanced technologies (NECEC Reply Brief at 2-3). Acadia Center also supports reforms to rate design that correct for significant cost shifts, such as the MMRC (Acadia Center Reply Brief at 4-5). However, NECEC and Acadia Center, along with DOER, argue that the Company's proposed Access Fee would not meet the Department's rate design goals of fairness and efficiency (DOER Brief at 10; Acadia Center Brief at 10; NECEC Brief at 39). In particular, DOER contends that the Access Fee is inconsistent with the Department's rate design goal of fairness as the Company's proposal targets only those DG facilities that export all power to the grid and not those that consume some power on-site (DOER Brief at 10).

Further, NECEC maintains that National Grid's Access Fee is contrary to the Department's rate design goal of sending efficient price signals because the Company failed to appropriately allocate any costs associated with stand-alone DG facilities in a fair and equitable manner as required under G.L. c. 164, § 142, and it did not consider various benefits of DG[338] (NECEC Brief at 39). Additionally, NECEC joins Vote Solar in arguing that the Department must reject the Company's proposed Access Fee because the Company failed to consider the impacts of its rate design proposal on the successful development of energy efficiency and DG, as required under G.L. c. 164, §§ 141, 142 (NECEC Brief at 39, 42; NECEC Reply Brief at 13; Vote Solar Brief at 22-23; Vote Solar Reply Brief at 12-13).

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338 As an example of a benefit that DG provides to the grid, NECEC cites avoided line losses from using generation located near load rather than transporting generation from a more distant source (NECEC Brief at 39-40).

b. National Grid

i. Evidentiary Support for the Proposed Access Fee

The Company argues that it is experiencing a growing cost shift from net metering customers to non-net metering customers from increased net metering incentives,[339] and that the bulk of distribution service costs are recovered through the variable portion of distribution rates,[340] instead of through fixed rates (Company Brief at 213-215). Further, the Company contends that the price for distribution service should be based on transparent and efficient rate designs that reflect the costs to provide service to both DG and non-DG customers (Company Brief at 212-213). As such, the Company proposes the Access Fee to reflect the costs imposed on the distribution system by the stand-alone DG facilities (Company Brief at 212-214, 228).

The Company argues that it proposed to set the Access fee at the same values as the demand charges proposed for Rates G-2 and G-3 customers because stand-alone DG customers use the distribution system for exporting electricity in the same way that customers on Rates G-2 and G-3 use the distribution system to import electricity (Company Brief at 229 citing Exhs. DPU-12-4, AG-27-10; Company Reply Brief at 95-96). More specifically, the Company contends that whether a particular customer imports or exports electricity, that customer relies on the electric distribution system and the services provided by the Company, and imposes a demand on the distribution system for which the system must be designed to

339 The Company calculates that the net costs to customers from net metering amounts to $27.99 million in 2014 and $53.14 million in 2015 (Exh. EFCA 1-3, Att. 1-3-2).

340 In addition to net metering credits, the Company contends that the cost shift consists of (1) O&M costs; (2) energy, transmission and distribution costs and (3) short- and long-term investments to support DG (Exhs. EFCA 1-3; EFCA 1-9; EFCA 1-11; EFCA 2-7; LI 1-10; AG-27-8).

accommodate (Company Brief at 229, citing, Exhs. NG-PP-Rebuttal-1, at 33; AG-27-10; Company Reply Brief at 95). Thus, the Company asserts that the proposed Access Fee has been appropriately set at the same values as the demand charges proposed for customers in Rate G-2 and Rate G-3, respectively (Company Brief at 229, citing Exh. DPU-12-4; Company Reply Brief at 95-96).

The Company argues that while Department precedent requires companies to design rates based on cost causation as well as balancing a number of oft-competing policy goals, there are practical limitations in establishing the level of the cost to serve and recovering those costs from customers (Company Brief at 211-212).[341] The Company contends that many of the criticisms of its rate proposals would require the Company to undertake an unprecedented level of precision in determining cost-causation; such an undertaking is not practical or required for ratemaking purposes (Company Brief at 212).

Further, National Grid rejects any notion that is has not met its burden of proof relative to the proposed Access Fee because it has not conducted special cost studies to demonstrate that the costs incurred to flow electricity in one direction are the same as the costs to flow the electricity in the other direction (Company Brief at 230, citing, DOER Brief at 9-10; EFCA Brief at 23; NECEC Brief at 37-38; Company Reply Brief at 96). The Company claims that such an analysis may not be possible, and even if it were, it would be meaningless because the distribution system still has to be constructed to meet demand, regardless of which way electricity flows (Company

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341 For example, the Company notes that costs are generally not calculated for individual customers, but rather for groups of homogenous customers with similar cost-causation attributes; and Department goals of simplicity, continuity, and earnings stability may temper the implementation of cost-based rates (Company Brief at 212, Exh. NG-PP-1, at 39-41).

Brief at 230, citing Exh. AG-27-10; Company Reply Brief at 96-97). Further, the Company asserts that the Intervenors and Limited Intervenors have provided no basis for the claim that the costs incurred to transport power away from a stand-alone DG facility is different from the costs incurred to transport power to a similarly sized retail customer (Company Brief at 231, citing Tr. 12, at 1330-1336; Company Reply Brief at 97).

The Company also dismisses any claims that the proposed Access Fee fails to account for any benefits of stand-alone DG facilities associated with their contribution toward distribution capacity (Company Brief at 231, citing, Attorney General Brief at 142-143; DOER Brief at 9-10; EFCA Brief at 23-25; NECEC Brief at 39-41; Company Reply Brief at 97). The Company contends that the record shows that stand-alone DG projects have been constructed in areas remote from load and that the generation from these facilities does not typically match feeder, substation, or system peak loads (Company Brief at 231, citing Exh. NG-PP-Rebuttal-1, at 37; Company Reply Brief at 97). Therefore, according to the Company, the claimed distribution capacity benefits of stand-alone DG facilities are "illusory" (Company Brief at 231; Company Reply Brief at 97). Further, National Grid argues that the record shows that the Company does consider solar capacity in its load forecasting methodology, as well as using actual measured peak loads on feeders and at substations (Company Brief at 231; Company Reply Brief at 97). Thus, the Company asserts that any load relief benefits created by solar will be realized over time in a similar fashion as the load relief provided by over 30 years of energy efficiency programs and services (Company Brief at 231; Company Reply Brief at 97).

With respect to system benefits from DG, the Company maintains that: (1) while correctly located DG may provide benefits, it has little hard evidence of such benefits within its

service territory;[342] and (2) system benefits of solar DG already have been assumed by the Commonwealth through implementation of net metering and the solar carve-out incentives (Company Brief at 215-216; Exh. NG-PP-Rebuttal-1, at 37). The Company alleges that, in light of these solar DG incentives, counting distribution system benefits from solar DG as an offset to distribution system costs would constitute double-counting, creating bill impacts to all customers (Company Brief at 216). The Company asserts that performing a cost-benefit or value-of-solar study to establish rates, as suggested by the Limited Intervenors, would be a departure from the Department's traditional ratemaking framework that raises more questions than it answers (Company Brief at 216).

ii. MMRC and Solar Act

On brief, the Company repeats its positions set forth in rebuttal testimony regarding the propriety of the proposed Access Fee in the context of § 139(j) and the MMRC (Company Brief at 231-233; Company Reply Brief at 97-99; see Section XIV.A.1.c above). In particular, the Company argues that: (1) the Department has the authority to approve the Access Fee irrespective of § 139(j); (2) assuming that the requirements of the statute apply to the proposed Access Fee, the requirements have been satisfied; and (3) by the time the proposed Access Fee is imposed, the 1600-megawatt threshold will likely be achieved (Company Brief at 231-233; Company Reply Brief at 97-99).

342 The Company contends that any distribution benefits from stand-alone DG facilities are illusory as record evidence shows that stand-alone DG projects have been constructed in remote areas away from load and do not match feeder, substation or system peak loads; any load relief benefits created by solar will only be realized over time similar to energy efficiency programs (Exh. NG-PP-Rebuttal-1, at 37; Company Brief at 231; Company Reply Brief at 97).

iii. Rate Design Issues

The Company does not specifically address the arguments of the Intervenors and Limited Intervenors regarding whether the proposed Access Fee meets the Department's rate design goals. However, the Company argues that its rate design proposals, which include the proposed Access Fee, meet the Department's rate design goals, represent a substantial improvement over its current rate design, and are the first step in a process towards an optimal rate design, which would include both customer and demand charges for each rate class (Company Brief at 213-214).

3. Analysis and Findings

National Grid argues that its proposed Access Fee is necessary to recover costs imposed on the distribution system by stand-alone DG facilities that take service under Rate G-1, but use the distribution system in the same manner as a typical Rate G-2 or Rate G-3 customer does (Exhs. NG-PP-1, at 74; AG-27-8; Tr. 5, at 653). According to National Grid, stand-alone DG facilities do not pay for O&M and some capital costs that they impose on the Company's distribution system (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3; AG-27-8; LI 1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NeCEC-1-13; NECEC-1-19). National Grid claims that stand-alone DG facilities' lack of contribution creates a growing cost shift, as the Company is required to socialize these costs by recovering them from all distribution customers (Company Brief at 212-214, 228-229).

As noted above, the Company claims that interconnection costs for stand-alone DG facilities do not include the costs associated with: (1) the recovery of ongoing O&M and the replacement of interconnection equipment; (2) T&D and non-T&D service for continued use of

the electric power system; (3) short term and long term investments to support enhanced quantities of DG on the electric power system; and (4) the interval metering required for the stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; DPU-12-3, at 1; DPU-21-3; AG-27-8; LI-1-22; EFCA-1-9, at 2; EFCA-1-10, at 2; EFCA-1-11; NECEC-1-13; NECEC-1-19). The record shows, however, that with the exception of interval meters, the Company has not quantified the costs that it contends stand-alone DG facilities impose on its distribution system (Exhs. EFCA 1-9, at 2; EFCA-1-10, at 2; NECEC 1-13, NECEC 1-19; Tr. 5, at 647-654). For instance, the Company identifies several categories of O&M associated with system modifications to stand-alone DG facilities to estimate O&M costs, but it does not quantify the actual O&M costs incurred by operating stand-alone DG facilities (Exhs. DPU-29-8; LI-1-10, EFCA-1-9, at 2, EFCA-1-11, EFCA-2-7, NECEC-1-13, DPU-21-3, Tr. 5, at 646, 652-654). Further, National Grid has not specifically quantified T&D and non-T&D costs related to use of the Company's system by stand-alone DG facilities (Tr. 5, at 649-651). In addition, the Company identifies, but does not quantify, other short- and long-term capital investments it states will need to be made to accommodate higher penetration of stand-alone DG facilities on its distribution system (Exhs. LI 1-10, LI 1-22, EFCA 1-9, EFCA 1-11). Rather, apart from the interval meters, the Company seems to rely on the allocated COSS applicable to the Rate G-2 and Rate G-3 classes as the cost basis for the proposed Access Fee (Tr. 5, at 644-645, 646, 648, 650-651).

Based on these considerations, we find that the amount of costs that the Company seeks to recover through the proposed Access Fee is not based on sufficient quantification of all of the costs that stand-alone DG facilities impose, but rather rests primarily on demand-related costs of

Rate G-2 and Rate G-3 customers, as determined by the allocated COSS (Exhs. DPU-12-4; DPU-29-9; AG-27-10; Tr. 5, at 652-653; Tr. 7, at 1122-1123). Further, the Company has not conducted an appropriate analysis to determine whether the reliance on the distribution system by a typical stand-alone DG facility is greater than, equal to, or less than customers on Rate G-2 and Rate G-3 (Exh. AG-27-10; Tr. 5, at 654). Therefore, we are not persuaded that the Company's reliance on costs attributable to Rate G-2 and Rate G-3 customers provides a sufficiently reliable cost basis to derive an Access Fee attributable to stand-alone DG customers who take service on Rate G-1. Accordingly, we decline to accept the Company's proposal.

The Department notes that our decision today should not be construed as a rejection of the concept of an Access Fee for stand-alone DG facilities.[343] The Department recognizes that there are distribution system-related costs that may be associated with these facilities for which the stand-alone DG customer should be responsible.[344] However, without a sufficiently reliable quantification of those costs, we are unable to approve the proposed Access Fee. Having rejected the Company's proposed Access Fee, we need not address the other arguments raised by the Intervenors, Limited Intervenors, and Limited Participants.

Further, we decline in this case to consider the Company's proposed Access Fee in the context of a MMRC under the Solar Act. The provision of the Solar Act permitting a MMRC

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343 The Company also considered as an alternative proposal to assign stand-alone DG facilities to retail delivery service tariffs commensurate with the size of the DG unit, such as Rate G-2 or Rate G3 (Exh. NG-PP-1, at 75). The Department is not necessarily opposed to such a concept, but notes that such a proposal would need to be supported by sufficient evidence showing that the costs attributable to the stand-alone DG facility are commensurate with costs caused by Rate G-2 or Rate G-3 customers.

344 The Department also recognizes that there are distribution system related revenues that are associated with net metering (RR-DPU-26).

proposal was enacted after the filing of this base rate case, and it contains specific procedural requirements that have not been satisfied here.[345] The Department currently is evaluating the timeline and implementation of potential MMRC proposals. Net Metering Rulemaking, D.P.U. 16-64-D at 16-17 (2016). Therefore, at the appropriate time, the Company may submit a proposal for a MMRC pursuant to § 139(j).[346]

Finally, we find that National Grid has provided sufficient quantification of the $1,690 cost of the interval meters required for stand-alone DG facilities (Exhs. NG-PP-1, at 74-75; NECEC-1-19 & Att.). Therefore, we allow the Company to recover this cost from new stand-alone DG facilities who take service under Rate G-1. The Company shall revise its Standards of Interconnection of Distributed Generation tariff accordingly.

B. Application Fee for Simplified Distributed Generation Applications

1. Introduction

The Company's Standards for Interconnection of Distributed Generation tariff ("Interconnection Tariff") (M.D.P.U. No. 1248) includes a fee structure applicable to interconnecting DG customers that varies depending on the size and type of interconnection. The fee structure was originally approved by the Department in 2004 and more recently reviewed and approved in 2013 following a DG working group process, which included the electric distribution companies and many stakeholders. See Distributed Generation

345 In particular, we note that the Company first addressed the MMRC provision in its rebuttal testimony, after discovery closed, and approximately two weeks before evidentiary hearings began. There was no public hearing relative to a MMRC, or opportunity to comment from interested parties.

346 This statute requires a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes.

Interconnection, D.P.U. 11-75-E at 36, 40 (2013); Investigation Into Distributed Generation, D.T.E. 02-38-B at 41 (2004).

The Company's current Interconnection Tariff exempts interconnection fees for a generating facility using the "Simplified Process" of interconnecting to the Company's electric distribution system (Exhs. NG-RRP-1, at 18; EFCA-1-6, at 2; M.D.P.U. No. 1248, § 3.10 (Table 6)).[347] However, the current tariff includes a $4.50 per kW interconnection fee for customers that choose either the Expedited Process,[348] or the Standard Process,[349] of interconnecting (M.D.P.U. No. 1248, § 3.10 (Table 6)).

2. Company Proposal

The Company proposes to assess a $28.00 one-time application fee for interconnecting DG customers that use the Simplified Process (Exhs. NG-MLR-1, at 21; NG-RRP-1, at 18;

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347 The Simplified Process is applicable to interconnecting customers (i) using certain single-phase inverter-based facilities with power ratings of 15 kilowatt or less at locations receiving single-phase, secondary service from a single-phase transformer, or (ii) using certain three-phase inverter-based facilities with power ratings of 25 kilowatt or less at locations receiving three-phase, secondary service from a three-phase transformer configuration, and requesting an interconnection on a radial electric system where the aggregate generating facility capacity is less than 15 percent of feeder/circuit annual peak load and, if available, line segment (M.D.P.U. No. 1248, § 3.1). This process is the fastest and least costly interconnection path (M.D.P.U. No. 1248, § 3.1).

348 The Expedited Process is open to certain larger interconnecting customers that do not qualify for the Simplified Process or the Standard Process (M.D.P.U. No. 1248, §§ 3.3, 3.10 (Table 6)).

349 The Standard Process is open to any size interconnecting customer, but it has the longest maximum application time period and highest potential costs (M.D.P.U. No. 1248, §§ 3.4, 3.10 (Table 6)).

NG-PP-24, at 286 (proposed M.D.P.U. No. 1285 (Table 6)); Tr. 7, at 1160).[350] The Company states the application fee is intended to cover costs associated with the intake and processing of the Simplified Process applications, such as: (1) reviewing applications for accuracy and completeness; (2) performing a technical screening based on the proposed equipment and characteristics of the local electric power system; (3) answering questions about the interconnection process; (4) providing the customer with status updates by email and/or phone; (5) reviewing completion documentation; (6) authorizing interconnection; and (7) validating processing timelines with customers in anticipation of annual reports to the Department (Exh. DPU-29-12; Tr. 7, at 1161-1162).

National Grid states that the primary reason for the proposed application fee is the significant growth in the number of Simplified Process applications on radial circuits received by the Company in recent years, and the associated cost of processing those applications (Exhs. NG-RRP-1, at 18-19; EFCA-1-6, at 2; Tr. 7, at 1163). In particular, National Grid notes that during the test year, the Company processed 13,027 Simplified Process applications, which was an increase of 8,821 applications (or 210 percent) from the previous year (Exh. NG-RRP-1, at 18-19).[351]

The Company derived the $28.00 application fee by considering the current application fee of $4.50 per kW applicable to interconnecting customers applying for interconnection through the Expedited or Standard Process. More specifically, the Company first determined

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350 The Company does not propose any changes to the Expedited or Standard Process fees (see Exh. NG-PP-24, at 286 (proposed M.D.P.U. No. 1285 (Table 6)).

351 The Company states that from approximately 2004 to 2006, the Company received only 64 Simplified Process applications (Exh. EFCA-1-6, at 2).

that the total capacity in kW of the interconnecting customers that applied through the Simplified Process during the test year was 81,636 kW (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13). The Company then multiplied this total by the $4.50 per-kW application fee applicable to Expedited and Standard Process applications to arrive at $367,362 (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13). Next, the Company divided this total by the number of Simplified Process applications received during the test year of 13,027 and rounded to the nearest dollar to arrive at $28.00 (Exhs. WP-NG-PP-3g; AG-2-2, Att. 13; Tr. 7, at 1161). Finally, the Company notes that as part of its proposal, a revenue credit has been applied to its cost of service in the amount of $364,756 ($28.00 x 13,027) (Exhs. NG-RRP-1, at 19; NG-RRP-2, at 3 (Rev. 3); EFCA-1-6, at 2).

The Company states that the proposed application fee is an appropriate way to recover from DG customers the costs associated with the Simplified Process applications (Exh. EFCA-1-6, at 2). According to the Company, without the application fee, ratepayers would be at risk for these costs (Exh. EFCA-1-6, at 2).

3. Positions of the Parties

No party addressed the Company's proposal on brief. In its prefiled testimony, EFCA provided conditional support for the Company's proposal (Exh. EFCA-CG-1, at 29). However, EFCA submits that the application fee should be implemented in a manner that does not create an administrative burden or application delay due to the processing of payment (Exh. EFCA-CG-1, at 29). EFCA further maintains that the Company should make every effort to optimize the Simplified Process for applying for interconnection (Exh. EFCA-CG-1, at 29).

4. Analysis and Findings

The Department approved the current fee structure applicable to interconnecting DG customers in D.P.U. 11-75-E at 36. In that Order, the Department recognized that if electric distribution companies do not collect enough funds to cover the costs associated with the interconnection of DG, ratepayers risk paying for the unrecovered costs. D.P.U. 11-75-E at 36. The Department noted that such an outcome is inconsistent with the interconnection framework, whereby the interconnecting customers pay for costs associated with the applicable interconnection. D.P.U. 11-75-E at 36, citing D.T.E. 02-38-B at 13-14.

In the instant case, the Company has demonstrated that there has been a significant increase in Simplified Process applications in recent years (Exhs. NG-RRP-1, at 18-19; EFCA-1-6, at 2; Tr. 7, at 1163). The Company also has provided evidence of the nature of the tasks associated with processing the Simplified Process applications (Exh. DPU-29-12; Tr. 7, at 1161-1162). Given these considerations, we find that the Company is incurring costs associated with processing Simplified Process applications for which interconnecting DG customers should be responsible. Therefore, we find that an application fee is a reasonable and appropriate way to recover application-related costs from interconnecting customers and to prevent ratepayers from paying for any such unrecovered costs. See D.P.U. 11-75-E at 36; D.T.E. 02-38-B at 13-14. Further, while the Company's proposed $28.00 application fee may not be derived through a precise calculation of the specific costs associated with processing the Simplified Process applications, we conclude that the one-time fee is not so disproportionate to the scope of work necessary to process the applications as to render the fee unreasonable.

Finally, we acknowledge EFCA's concerns with respect to implementing the application fee and optimizing the Simplified Process for interconnection. However, there is nothing in the record that leads us to conclude that any further direction to the Company with respect to these concerns is warranted.

Based on these findings, we approve the Company's proposal to assess a one-time application fee of $28.00 for interconnecting DG customers that use the Simplified Process. In addition, the Department also approves the Company's proposed credit to revenues in the amount of $364,756. The Company is directed in its compliance filing to revise its Interconnection Tariff accordingly.

C. Summary of Charges Tariff

In the Company's last rate case, the Department directed National Grid to include a separate tariff that shows the approved charges for each rate class, which is referred to as the summary tariff. D.P.U. 09-39, at 442. The summary tariff is the sole tariff that states the current charges for each delivery service factor.[352] The Department found that the use of a summary tariff is administratively efficient, consumer-friendly, and consistent with Department precedent. See, e.g., D.P.U. 09-39, at 442; D.P.U. 07-71, at 197-198; D.T.E. 05-85, M.D.P.U. No. 190 (2005).

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352 The currently effective summary tariff shows for each rate class: (1) the M.D.P.U. number; (2) the applicable blocks of kWh hours use; (3) customer and other distribution charges; (4) other delivery service charges including pension and PBOP adjustment factor, RAAF, basic service adjustment, SFRF, revenue decoupling adjustment factor, solar cost adjustment factor, attorney general consultant expense factor, smart grid distribution adjustment factor, transition, transmission, renewable, and energy efficiency charges; and (5) the date of the last change of each rate (see M.D.P.U. Nos. 1-16-B, 1-16-C).

During the course of this proceeding, National Grid agreed to amend its standard summary tariff by including basic service pricing (Exh. DPU-18-11 & Atts.; Tr. 7, at 1183). Accordingly, the Department directs the Company in its compliance filing to include in its summary tariff, the basic service rates for each rate class, consistent with the summary tariffs for NSTAR Electric, Unitil, and WMECo, and to include the changes to the delivery service rates consistent with the directives in this Order (see M.D.P.U. Nos. 190-16-C, 290-16-C, 390-16-C (NSTAR Electric); 297 (Unitil); 1052-16-D (WMECo)).

D. Other Tariff Changes

The Company proposes changes to the following tariffs that are not addressed above or elsewhere in this Order: (1) Terms and Conditions for Distribution Service (proposed M.D.P.U. No. 1275); (2) Solar Cost Adjustment Provision (proposed M.D.P.U. No. 1281); (3) Optional Enhanced Metering Service (proposed M.D.P.U. No. 1283); and (4) Optional Interval Data Service (proposed M.D.P.U. No. 1284) (Exhs. NG-PP-1, at 79-80, 87; NG-PP-24, at 204-243, 275-278, 281-284). No party addressed the Company's proposed changes. The Department has reviewed the changes and we find that they are acceptable. National Grid, as part of its compliance filing, is directed to revise these tariffs accordingly.

National Grid also proposes changes to its Net Metering Provision (proposed M.D.P.U. No. 1279)[353] and its Standards for Interconnection of Distributed Generation (proposed

[353] The Company also proposes revisions to its Net Metering Provision and its Qualifying Facility Power Purchase Rate P (proposed M.D.P.U. No. 1286) to reflect the inclusion of the proposed Access Fee applicable to stand-alone DG facilities (Exhs. NG-PP-1, at 80; NG-PP-24, at 289-294). As discussed in Section XIV.A.3 above, the Department has rejected the proposed Access Fee and directed the Company to revise these tariffs accordingly.

M.D.P.U. No. 1285)[354] to implement the Company's proposal to bid capacity of customer-owned solar facilities in the forward capacity market (Exhs. NG-PP-1, at 80; NG-PP-24, at 257-272, 285-288). The proposed changes related to the forward capacity market are inconsistent with our findings in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, Interlocutory Order (February 9, 2016). Therefore, the Department disallows the proposed changes. The Company, as part of its compliance filing, is directed to revise these tariffs accordingly.

354 The Company also proposes revisions to its Standards for Interconnection of Distributed Generation to reflect the inclusion of a $28 application fee for some interconnecting DG customers (Exhs. NG-PP-1, at 80; NG-PP-24, at 285-288). As discussed in Section XIV.B.4 above, the Department has allowed the application fee and directed the Company to revise this tariff accordingly.

XV. SCHEDULES

A. Schedule 1 – Revenue Requirements and Calculations of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER	
COST OF SERVICE					
Total O&M Expense	418,651,872	(6,301,828)	(18,305,155)	394,044,888	
Depreciation & Amortization	126,675,702	0	6,690,139	133,365,841	
Taxes Other Than Income Taxes	72,425,197	(2,462,861)	(463,672)	69,498,664	
Interest on Customer Deposits	87,581	0	0	87,581	
Income Taxes	64,398,568	190,633	(8,614,404)	55,974,797	
Return on Rate Base	145,879,317	422,252	(11,141,024)	135,160,545	
Additional Uncollectibles (Revenue Deficiency)	2,595,005	(114,982)	(395,894)	2,084,129	
Total Cost of Service	830,713,242	(8,266,786)	(32,230,011)	790,216,446	
OPERATING REVENUES					
Base Distribution Revenues	587,866,996	0	0	587,866,996	
Other Operating Revenues	31,585,294	1,093,917	0	32,679,211	
Total Operating Revenues	619,452,290	1,093,917	0	620,546,207	
Total Revenue Deficiency	**211,260,952**	**(9,360,703)**	**(32,230,011)**	**169,670,239**	*

*The Total Revenue Deficiency represents $101,000,617 in additional base distribution revenue and $68,669,622 currently recovered through reconciling charges and transferred for recovery in base distribution revenue in this proceeding.

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

B. Schedule 2 – Operation and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Other Operation & Maintenance Expenses	378,462,961	(477,379)	0	377,985,582
Purchased Power	1,120,435,761	0	0	1,120,435,761
Transmission O&M	413,579,624	0	0	413,579,624
Environmental Response Fund	4,017,471	0	0	4,017,471
Storm Recovery Outside of Rate Base	44,675,247	0	0	44,675,247
Pension/OPEB Expense	31,789,638	0	0	31,789,638
Energy Efficiency O&M	264,485,767	477,379	0	264,963,146
Storm Fund	4,300,000	0	0	4,300,000
Uncollectible Accounts- Delivery Write-offs	62,292,694	0	0	62,292,694
	2,324,039,162	0	0	2,324,039,162
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Eliminate Tracked Items:				
Purchased Power	(1,119,347,926)	0	0	(1,119,347,926)
Transmission O&M	(423,091,751)	0	0	(423,091,751)
Energy Efficiency	(264,485,767)	(477,379)	0	(264,963,146)
Storm Recovery Outside of Rate Base	(44,675,247)	0	0	(44,675,247)
Pension / OPEB	(31,789,638)	0	0	(31,789,638)
Eliminate Commodity Procurement Administration Costs (Basic Service)	(579,215)	0	0	(579,215)
O&M Recovered Through Solar Phase II Cost Recovery Factors	(191,093)	0	0	(191,093)
O&M Recovered Through SmartGrid Cost Recovery Factors	(11,623,419)	0	0	(11,623,419)
Eliminate O&M Recovered Through Purchase of Receivables (POR) program	(404,429)	0	0	(404,429)
Rent Expense adjustment for Information System Projects & Facilities Expense	(3,259,652)	(2,314,286)	(195,172)	(5,769,110)
Eliminate General/Institutional Advertising	(157,453)	0	0	(157,453)
Eliminate Senior Executive Expenses	(122,772)	0	0	(122,772)
Eliminate Intercompany Equity Maintenance Agreement	(7,900,632)	0	0	(7,900,632)
Eliminate Rate Case Expense related to Docket No. DPU 09-39	(327,510)	0	0	(327,510)
One Time/Out of Period Adjustments	(2,339,447)	0	0	(2,339,447)
Paperless Billing Credit	859,993	0	0	859,993
Out-of-period Service Co allocation corrections	0	262,256	0	262,256
FAS 112	2,753,539	(416,331)	0	2,337,208
Airplane rental charge	0	(7,138)	0	(7,138)
Postage expense	0	(283,605)	0	(283,605)
Uncollectibles Expense	(43,633,220)	(1,043,371)	0	(44,676,591)
POST TEST YEAR ADJUSTMENTS:				
Salary and Wage Adjustments	10,996,071	(2,029,898)	(1,280,399)	7,685,773
Health Care Expense	(250,830)	(13,138)	(86,778)	(350,746)
Group Insurance Expense	111,969	(28,591)	(8,923)	74,455
Employee Thrift	393,144	(90,651)	(43,272)	259,220
Facilities and Information Systems Lease Expense	10,869,709	(742,205)	(134,915)	9,992,589
Overnight Personnel for Priority 1 & 2 Calls	108,120	(108,120)	0	0
Uninsured Claims	(447,281)	(459,778)	0	(907,059)
Insurance Premiums	(1,069,836)	36,602	0	(1,033,234)
Other O&M Inflation Adjustment	6,311,460	(998,556)	(1,029,279)	4,283,625
Rate Case Expense	302,557	(53,436)	0	249,121
Regulatory Assessments	0	1,006,497	0	1,006,497
MECO IFA Expenses	(394,628)	(799,344)	0	(1,193,973)
Environmental Response Fund	176,367	(25,310)	(17,677)	133,380
Storm Fund	9,700,000	0	(5,103,257)	4,596,743
Hardship Protected Accounts*	8,121,527	2,283,955	(10,405,483)	0
Sum of O&M Expense Adjustments	(1,905,387,291)	(6,301,828)	(18,305,155)	(1,929,994,274)
Total O&M Expense	**418,651,872**	**(6,301,828)**	**(18,305,155)**	**394,044,888**

*Hardship Expense moved to Schedule 3

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	126,675,702	0	(1,431,389)	125,244,313
Hardship Protected Accounts*	0	0	8,121,527	8,121,527
Total Depreciation and Amortization Expense	**126,675,702**	**0**	**6,690,139**	**133,365,841**

*From Schedule 2

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

D. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	3,995,978,017	0	(332,000)	3,995,646,017
LESS:				
Reserve for Depreciation	1,687,662,861	(3,345,864)	0	1,684,316,997
Net Utility Plant in Service	2,308,315,156	3,345,864	(332,000)	2,311,329,020
ADDITIONS TO PLANT:				
Materials and Supplies	24,453,573	(1,222,533)	(378,821)	22,852,219
Cash Working Capital	72,905,019	(4,885,103)	(15,695,830)	52,324,086
Total Additions to Plant	97,358,592	(6,107,636)	(16,074,651)	75,176,305
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	577,103,094	(7,955,529)	0	569,147,565
Customer Deposits	29,839,942	0	0	29,839,942
Customer Advances	4,397,172	0	0	4,397,172
Total Deductions from Plant	611,340,208	(7,955,529)	0	603,384,679
RATE BASE	1,794,333,540	5,193,757	(16,406,651)	1,783,120,647
COST OF CAPITAL	8.13%	8.13%	-0.55%	7.58%
RETURN ON RATE BASE	**145,879,317**	**422,252**	**(11,141,024)**	**135,160,545**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 5 – Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,235,000,000	47.93%	5.56%	2.670%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% *
Common Equity	$1,339,156,000	51.98%	10.50%	5.460%
Total Capital	$2,576,415,000	100.00%		8.13%
Weighted Cost of				
Debt				2.67%
Preferred				0.00%
Equity				5.46%
Cost of Capital				8.13%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,235,000,000	47.93%	5.56%	2.670%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% *
Common Equity	$1,339,156,000	51.98%	10.50%	5.460%
Total Capital	$2,576,415,000	100.00%		8.13%
Weighted Cost of				
Debt				2.67%
Preferred				0.00%
Equity				5.46%
Cost of Capital				8.13%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$1,300,000,000	49.22%	5.21%	2.560%
Preferred Stock	$2,259,000	0.09%	4.44%	0.00% **
Common Equity	$1,339,156,000	50.70%	9.90%	5.020%
Total Capital	$2,641,415,000	100.00%		7.58%
Weighted Cost of				
Debt				2.56%
Preferred				0.00%
Equity				5.02%
Cost of Capital				7.58%

*0.003893%

**0.003797%

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F. Schedule 6 – Cash Working Capital

		PER COMPANY		COMPANY ADJUSTMENT		DPU ADJUSTMENT	PER ORDER
	CWC%		CWC%		CWC%		
O&M Subject to Cash Working Capital	5.90%	378,462,961	-0.06%	(2,684,767)	0%	(2,583,566)	373,194,627
Energy Efficiency	5.90%	264,485,767	-0.06%	477,379	0%	(264,963,146)	0
CTC Expense	1.88%	(2,887,862)	0.00%	11,958	0%	0	(2,875,904)
Transmission O&M	6.21%	413,579,624	0.00%	13,242,461	0%	0	426,822,085
Total		1,053,640,490		11,047,031		(267,546,712)	797,140,809
Taxes Other than Income Taxes							
Municipal Taxes	4.99%	56,269,342	0.04%	4,107,023	0%	(1,344,207)	59,032,158
Payroll Taxes - Company Portion							
Federal Unemployment	-12.42%	56,065	-0.04%	18,689	0%	(184)	74,570
State Unemployment	-13.40%	219,968	-0.10%	34,888	0%	(724)	254,132
FICA Expense - Weekly	9.40%	8,326,349	-0.02%	583,071	0%	(27,397)	8,882,023
FICA Expense - Monthly	7.21%	1,105,863	-0.03%	63,740	0%	(3,639)	1,165,964
Total		65,977,587		4,807,411		(1,376,151)	69,408,848
Payroll Taxes and Other Withholding							
FICA and Federal Withholding - Weekly	11.50%	27,271,963	-10.95%	(4,927)	0%	(89,735)	27,177,301
FICA and Federal Withholding - Monthly	12.49%	3,385,469	-10.90%	(11,875)	0%	(11,139)	3,362,455
State Income Tax Withholding - Weekly	-0.53%	5,585,890	1.07%	0	0%	(18,380)	5,567,510
State Income Tax Withholding - Monthly	-1.56%	701,277	3.15%	0	0%	(2,307)	698,970
Incentive Thrift - Weekly	10.88%	17,555,926	-10.93%	0	0%	(57,766)	17,498,160
Incentive Thrift - Monthly	10.99%	2,543,862	-10.99%	0	0%	(8,370)	2,535,492
Total		57,044,387		(16,802)		(187,697)	56,839,888
Amount Subject to Cash Working Capital		1,176,662,464		15,837,640		(269,110,560)	923,389,544
Total Cash Working Capital Allowance		**72,905,019**		**(4,885,103)**		**(15,695,830)**	**52,324,086**
Composite Lead Lag Factor				**5.70%**			**5.67%**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

G. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Municipal Tax	56,269,342	0	0	56,269,342
Payroll Tax	10,748,283	0	0	10,748,283
Other Taxes	3,496,809	0	0	3,496,809
Test Year Municipal Taxes	70,514,434	0	0	70,514,434
ADJUSTMENTS TO TAXES OTHER THAN INCOME:				
Normalizing adjustments:				
Municipal Tax	675,476	0	0	675,476
Payroll Tax	0	(564,304)	(163,969)	(728,273)
Other Taxes	(3,383,264)	0	0	(3,383,264)
Known & measurable adjustments:				
Municipal Tax	3,799,326	(1,467,955)	(244,031)	2,087,340
Payroll Tax	819,226	(430,602)	(55,672)	332,952
Total Adjustments	1,910,764	(2,462,861)	(463,672)	(1,015,769)
Total Municipal Tax	60,744,144	(1,467,955)	(244,031)	59,032,158
Total Payroll Tax	11,567,509	(994,906)	(219,641)	10,352,962
Total Other Tax	113,545	0	0	113,545
Taxes Other Than Income	**72,425,197**	**(2,462,861)**	**(463,672)**	**69,498,664**

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H. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	1,794,333,540	5,193,757	(16,406,651)	1,783,120,647
Return on Rate Base	145,879,317	422,252	(11,141,024)	135,160,545
Less:				
Interest Expense	47,908,706	138,673	(2,399,490)	45,647,889
Amort. Net Unfunded Deferred Tax Liability	440,768	0	1,637,317	2,078,085
Income Tax Impact of Flow Through Items	(274,007)	0	0	(274,007)
Amortization of Investment Tax Credits	707,081	0	0	707,081
Total Deductions	48,782,548	138,673	(762,173)	48,159,048
Taxable Income Base	97,096,769	283,579	(10,378,851)	87,001,497
Gross Up Factor*	1.6722	1.6722	1.6722	1.6722
Taxable Income	162,369,179	474,213	(17,355,938)	145,487,454
Mass Franchise Tax 8%	12,989,534	37,937	(1,388,475)	11,638,996
Federal Taxable Income	149,379,645	436,276	(15,967,463)	133,848,458
Federal Income Tax at 35%	52,282,876	152,696	(5,588,612)	46,846,960
Amort. Net Unfunded Deferred Tax Liability	(440,768)	0	(1,637,317)	(2,078,085)
Income Tax Impact of Flow Through Items	274,007	0	0	274,007
Amortization of Investment Tax Credits	(707,081)	0	0	(707,081)
Total Income Taxes	**64,398,568**	**190,633**	**(8,614,404)**	**55,974,797**

*1.672240803

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I. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
DISTRIBUTION REVENUES PER BOOKS	587,866,996	0	0	587,866,996
Other Operating Revenues	29,548,876	0	0	29,548,876
Adjustments to Other Operating Revenues				
Returned Check fee	0	8,516	0	8,516
Gain on sale of property	0	318,689	0	318,689
Pole Attachment Fees	0	766,712	0	766,712
Miscellaneous Fees	(27,570)	0	0	(27,570)
DG Application Fee	364,756	0	0	364,756
Solar Phase I Revenue	1,699,232	0	0	1,699,232
Total Adjustments	2,036,418	1,093,917	0	3,130,335
Total Other Revenues	31,585,294	1,093,917	0	32,679,211
Adjusted Total Operating Revenues	**619,452,290**	**1,093,917**	**0**	**620,546,207**

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J. Schedule 10 – Allocation to Rate Classes

For illustrative purposes only

Department Approved Revenue Increase 169,670,239

Rate Class	Per Final Revenue Allocation: Proposed COSS Target Revenue (1)	Current Revenue (2)	Proposed Deficiency at EROR (3)	Percent Increase at EROR (4)	Total Revenue Based on Current Rates (5)	Department Approved Revenue Increase at EROR (6)	Percent Increase at Department Approved Revenue Increase (7)	Section 20 Revenue Increase Cap (8)	Excess Increase to be Re-allocated (9)	Per Order Re-allocation to Uncapped Rate Classes (10)	Uncapped and Re-allocated Department Approved Revenue Increase (11)	Per Order Revenue to be Re-allocated 200% Cap (12)	Per Order Re-allocation to Uncapped Rate Classes (13)	Department Approved Revenue Requirement (14)	Department Approved Revenue Increase (15)
Residential R-1/R-2	$444,918,329	$314,481,570	$130,436,759	41.48%	$1,893,254,281	$107,558,481	34.20%	$189,325,428	$0	$6,372,692	$113,931,174	$0	$39,453	$428,452,197	$113,970,627
Residential R-4	$748,283	$336,782	$411,501	122.19%	$2,624,869	$373,284	110.84%	$262,487	$110,797		$262,487	$68,083	$0	$531,185	$194,404
Small C&I G-1	$94,857,778	$101,635,361	($6,777,583)	-6.67%	$466,269,132	($11,667,548)	-11.48%	$46,626,913	$0	$1,358,490	($10,309,058)	$0	$8,410	$91,334,714	($10,300,647)
Medium C&I G-2	$90,220,476	$56,293,156	$33,927,320	60.27%	$504,774,535	$29,175,068	51.83%	$50,477,454	$0	$1,290,547	$30,465,615	$0	$7,990	$86,766,761	$30,473,605
Large C&I G-3	$138,402,752	$101,210,034	$37,192,718	36.75%	$1,231,863,068	$29,614,935	29.26%	$123,186,307	$0	$1,975,422	$31,590,357	$0	$12,230	$132,812,622	$31,602,587
Street Lighting	$29,980,323	$13,910,094	$16,070,229	115.53%	$37,296,584	$14,616,012	105.07%	$3,729,658	$10,886,354		$3,729,658	$0	$0	$17,639,752	$3,729,658
Total Company	$799,127,941	$587,866,997	$211,260,944	35.94%	$4,136,082,470	$169,670,234	28.86%	$413,608,247	$10,997,152	$10,997,152	$169,670,234	$68,083	$68,083	$757,537,231	$169,670,234

Notes:

(1) Exhibit DPU-33-8, Att. at 37, line 24
(2) Exhibit DPU-33-8, Att. at 37, line 1
(3) Column (1) - Column (2)
(4) Column (3) ÷ Column (2)
(5) Exhibit DPU-33-8, Att. at 37, line 21 / Test Year Billing Determinants multiplied by current rates for each rate class.
(6) Per Cost of Service Study
(7) Column (6) ÷ Column (2)
(8) Column (5) x 10%
(9) If Column (8) > Column (6), then $0. If Column (8) < Column (6), then Column (6) - Column (8)
(10) [(Column (2) + Column (6) for applicable rate class) ÷ (sum of Column (2) + Column (6) for uncapped rate classes)] x Total Column (9)
(11) Column (6) - Column (9) + Column (10)
(12) If [Column (11) / Column (2)] > 2*[Total of Column (7)], then Column (11) - [Column (2) * (2*Total of Column (7)]. If not, then zero.
(13) [(Column (2) + Column (6) for applicable rate class) ÷ (sum of Column (2) + Column (6) for uncapped rate classes)] x Total Column (12)
(14) Column (2) + Column (11) + Column (13)
(15) Column (14) - Column (2)

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XVI. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That tariffs M.D.P.U. Nos. 1264 through 1286, as applicable to Massachusetts Electric Company, and tariffs M.D.P.U. Nos. 576 through 587 and M.D.P.U. Nos. 1275 through 1286, as applicable to Nantucket Electric Company, filed on November 6, 2015, to become effective, after suspension by the Department, on October 1, 2016, are DISALLOWED; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company shall file new schedules of rates and charges designed to increase annual electric revenues by $169,670,239; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company shall comply with all other orders and directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/

Angela M. O'Connor, Chairman

/s/

Robert E. Hayden, Commissioner

XVII. PARTIAL DISSENT OF COMMISSIONER WESTBROOK

While I join with the majority's conclusions for much of this decision, I dissent specifically from the conclusions found in Sections V.D.4 and XII.E above, with respect to the inclusion of property taxes in the Company's CIRM and the ROE. For the reasons below, I am of the opinion that the Department should not expand National Grid's CIRM to include recovery of property taxes. The Department recently excluded property taxes from the capital cost recovery mechanism approved for Fitchburg Gas and Electric Light Company (Electric Division) ("Fitchburg"), and I see no reason to treat National Grid's proposal differently.[355]

In D.P.U. 09-39, the Department approved a reconciling mechanism, then referred to as the capital expenditures ("CapEx") mechanism, which allowed the Company to recover an annual revenue requirement on incremental capital investments. D.P.U. 09-39, at 80. We did so, recognizing that revenue decoupling would remove the Company's opportunity to earn additional revenue to fund projected capital expenditures from growth in sales between rate proceedings. D.P.U. 09-39, at 79-80. National Grid's CapEx does not provide for inclusion of property taxes in the recovery mechanism. In D.P.U. 15-80/D.P.U. 15-81, at 52, we approved a capital investment recovery mechanism for Fitchburg that was designed to operate similar to National Grid's CapEx mechanism. One way in which the Department revised Fitchburg's CCAM to make it consistent with National Grid's CapEx was the exclusion of property taxes from the calculation of Fitchburg's CCAM. D.P.U. 15-80/D.P.U. 15-81, at 55-56.

In this Order, the Department finds that National Grid has adequately demonstrated a continued need to recover incremental costs associated with capital expenditure programs

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355 Fitchburg's capital investment recovery mechanism approved by the Department is the capital cost adjustment mechanism ("CCAM"). D.P.U. 15-80/D.P.U. 15-81, at 1.

between base distribution rate proceedings (see Section V.D above). In approving National Grid's CIRM, this Order, however, modifies the existing CapEx in three ways. First, the Department has increased the investment cap from $170 million to $249 million, allowing the Company to recover more of its capital investment between rate cases. Second, the Department has removed the CIRM from the RDM tariff, thereby separating the rate caps and allowing the Company further latitude to recover costs associated with capital investments between rate cases. Third, the majority has found it appropriate to include the recovery of property taxes associated with capital investments as part of the CIRM allowing the Company to recover property tax expense outside of the $249 million investment cap. While I find the first two modifications to be appropriate, I am of the opinion that including property taxes in the CIRM has expanded this mechanism beyond its original purpose and that such expansion is not in the best interests of ratepayers.

Previously, the Department has only allowed capital investment recovery mechanisms upon a finding that the mechanism strikes the appropriate balance between: (1) providing a company with sufficient funds to ensure safe and reliable electric service; and (2) protecting ratepayers from overinvestment in capital infrastructure. D.P.U. 09-39, at 81-82; D.P.U. 15-80/D.P.U. 15-81, at 51. As noted above, the Department rejected a similar proposal by Fitchburg to include property taxes in the calculation of its capital cost recovery mechanism. D.P.U. 15-80/D.P.U. 15-81, at 54. In that case, the Department stated that the revised CCAM, including the exclusion of property taxes in the calculation of the capital cost recovery mechanism, strikes an appropriate balance of providing Fitchburg with a source of funds to invest in capital expansion projects between rate cases, while protecting ratepayers from the

Company's incentive to over-invest. D.P.U. 15-80/D.P.U. 15-81, at 54. See also D.P.U. 07-50-A at 48. Further, the Department explained that the purpose of a capital cost recovery mechanism is not to provide a company with dollar-for-dollar recovery of capital investments between rate cases, but to provide rate relief in between base distribution rate cases to fund capital investments that were available to be funded through sales growth prior to decoupling. D.P.U. 15-80/D.P.U. 15-81, at 54. Thus, in my opinion, the inclusion of property taxes in the National Grid's CIRM is contrary to the intended goal of capital investment recovery mechanisms. I continue to support that concept of the CIRM and conclude that excluding property taxes strikes the appropriate balance.

In this case, I do not believe that excluding property taxes in the calculation of the CIRM will adversely affect the Company's financial well-being. The Company would recover its property taxes expense under traditional ratemaking as an O&M expense in the Company's cost of service. Moreover, while the need for a capital cost recovery mechanism is specific to each company, I see no evidence in the record that warrants different treatment between Fitchburg and National Grid with respect to the underlying policy goals of a capital investment recovery mechanism.

I disagree with the majority that "exclusion of [property taxes] does not provide the appropriate rate relief between base rate proceedings" (see page 57 above). By increasing the investment cap and separating the CIRM and RDM rate caps, the Department has provided sufficient support for the Company to fund its capital expenditures. Additionally, including recovery of property taxes through the CIRM, in my opinion, provides the Company with more

than adequate funding to compensate for the effect of decoupling.[356] While the majority notes that the inclusion of a portion of property taxes in National Grid's CIRM does not constitute dollar-for-dollar recovery (see page 58 above), it is my opinion that the inclusion of property taxes expands the CIRM beyond the intended purpose aligning it more with a dollar-for-dollar recovery mechanism.

Further, unlike the gas companies' targeted capital investment recovery factors that include property tax recovery (e.g., TIRF, GSEP),[357] the Company's CIRM is broad. The TIRF and the GSEP programs are more narrow, focus on a specific public safety issue identified by the Legislature, and the GSEPs require the Department's approval of a capital investment plan. See, e.g., Boston Gas Company/Colonial Gas Company, D.P.U. 14-132, at 3-5 (2015). Under the CIRM, however, the Company can recover any and all capital investments under the investment cap that are not recovered through another factor. Expanding the already broad CIRM to include property taxes is not necessary for the intended purpose of capital investment recovery mechanisms and will result in annual cost increases for ratepayers.

Lastly, the majority finds that an ROE of 9.90 percent is appropriate (see Section XII.E above). While I agree that 9.90 percent is within the range of reasonableness, I believe that a downward adjustment to the ROE that would still remain within the range of reasonableness is appropriate to more fully reflect the reduced risk to the Company as a result the CIRM, including property taxes, and our treatment of protected hardship account balances in Section VIII.J.3.

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356 A utility can file a base rate case with the Department under G.L. c. 164, § 94 if the utility determines that it is not earning sufficient revenues to fund its operations.

357 Targeted Infrastructure Recovery Mechanism ("TIRF"); Gas System Enhancement Plan ("GSEP").

Apart from these points and their consequences for other features of the final Order in this docket, I join in the remainder of the decision.

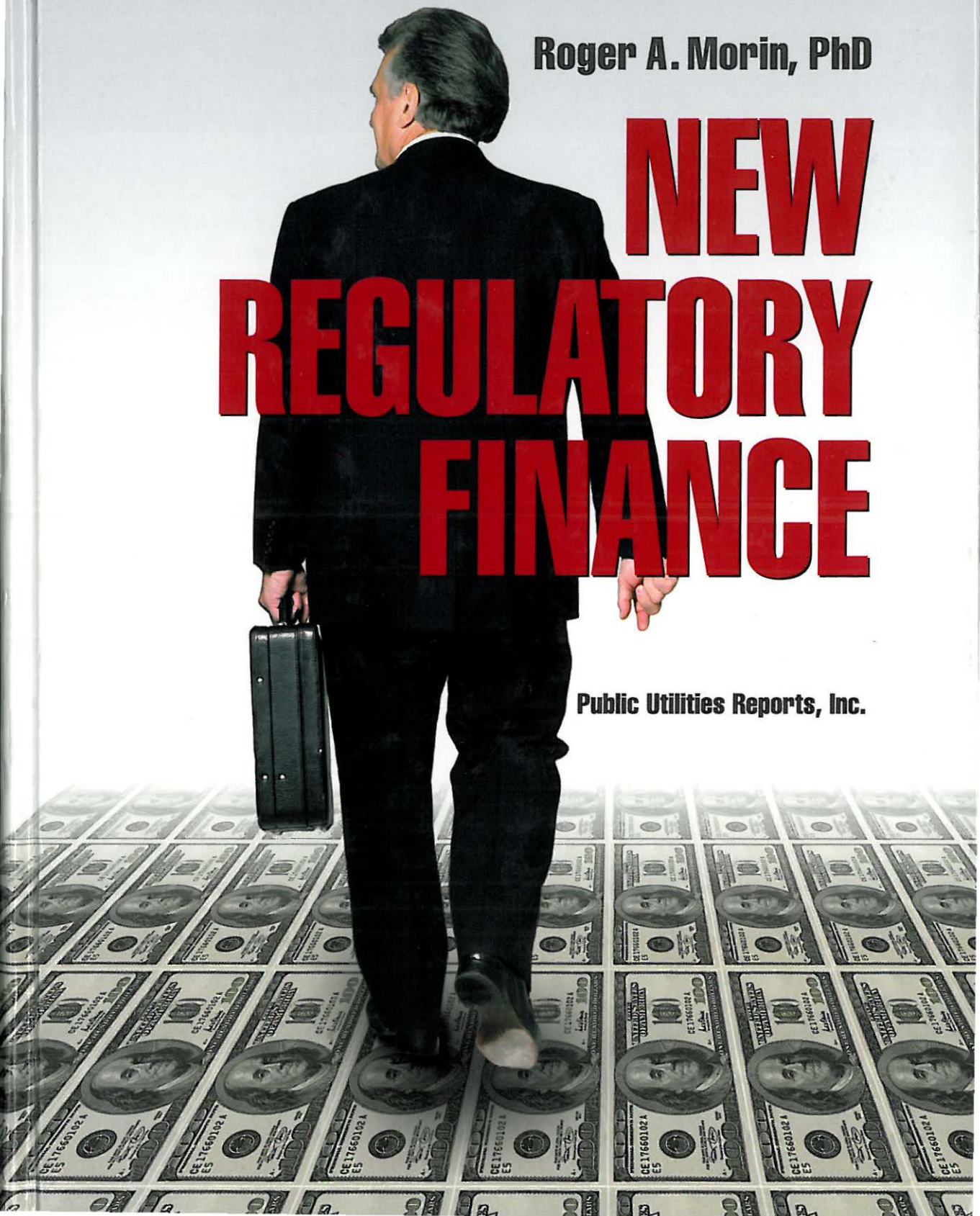
/s/

Jolette A. Westbrook, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

Roger A. Morin, PhD

NEW REGULATORY FINANCE



Public Utilities Reports, Inc.

Chapter 10
Flotation Cost Adjustment

This chapter demonstrates that an adjustment to the market-based cost of capital is necessary for flotation costs associated with the procurement of equity capital, and discusses the mechanics and controversies involved in applying this adjustment.

A typical utility is continuously issuing stock through its dividend reinvestment plan and employee stock option plan, and/or is selling new shares to the public on a regular basis in order to maintain its construction program and meet its mandated service requirements. The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs.

10.1 Flotation Cost Allowance

The simple fact of the matter is that common equity capital is not free. Flotation costs associated with common stock issues are very similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred, and if they are not expensed at the time of issue, they must be recovered through a rate of return adjustment. This is routinely done for bond and preferred stock issues by most regulatory commissions. To illustrate the conventional regulatory practice, consider this example. A utility company issues $100 million of 10-year bonds at an interest rate of 5%. Flotation costs are 2% of the amount of the proceeds, $2 million. The interest paid each year is $100 million x 5% = $5 million. The flotation cost of $2 million is amortized over the 10-year life of the bond, so that the amortization each year equals $2M/10 = $0.2 million. The cost of debt K_d is then:

$$K_d = \frac{\text{Interest} + \text{Amortization of flotation costs}}{\text{Principal} - \text{Unamortized flotation costs}}$$

$$= \frac{\$5{,}000{,}000 + \$200{,}000}{\$100{,}000{,}000 - \$2{,}000{,}000} = 5.31\%$$

The cost of debt needs to be increased by 31 basis points in order to allow for the recovery of flotation costs. The recovery process is very similar for common stock issues.

In the case of issues of new common equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have three major components:

approximately 2% and 4%–5%, respectively, of the amount of the proceeds from the issue. Moreover, the cost associated with the decline in stock price at announcement date represents approximately 1%–3% as a result of a large utility stock offering.

10.3 Application of the Flotation Cost Adjustment

This section formally demonstrates: (1) how and why it is necessary to apply a flotation cost allowance to the dividend yield component of the DCF model in order to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) why flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

An analogy with bond issues, as discussed in Brigham, Aberwald, and Gapenski (1985), is useful here in order to understand the treatment of issue costs in the case of common stock issues. In the case of bonds as seem earlier in the chapter, flotation costs are recovered over the life of the bond in two steps: (1) flotation costs are amortized over the life of the bond and the annual amortization charge is incorporated into revenue requirements, in much the same way that funds invested in utility plant are recovered through depreciation charges; (2) the unamortized portion of flotation costs is included in rate base, and a return is earned on the unamortized costs, in the same way that a return is earned on the undepreciated portion of a utility's plant. The recovery continues year after year until the recovery process is terminated, regardless of whether the utility raises new debt capital. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery continues whether the utility constructs new facilities or not.

Unlike the case of bonds, common stock has no finite life so that flotation costs cannot be amortized and therefore must be recovered by way of an upward adjustment to the allowed return on equity.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation

Cost of Capital

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marketability from the estimated publicly traded equivalent value. Two sets of studies to provide quantitative guidance for this are:

a. Restricted stock studies
b. Pre–IPO studies

2. *Adjust the discount rate.* Add percentage points to the discount rate used to discount the expected cash flows to present value.

A commonly used estimate of the minimum increase in the cost of equity for the lack of marketability of the subject closely held investment is to adjust the cost of equity for hypothetical flotation costs. This adjustment is recognition that the cost of capital for an illiquid investment is greater than the cost of equity capital for publicly traded companies. Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital. The cost of flotation is a function of size and risk. The greater the size of the hypothetical stock offering, the lower the flotation cost relative to the size of the offering. Obviously the flotation cost estimate understates the appropriate increase in the cost of equity capital due to lack of marketability in cases where the subject closely held business could never become public. In addition, the owner of a minority interest could never cause the business to become public.

We also discussed results of Ashok Abbott's study of the cost of illiquidity for public companies.

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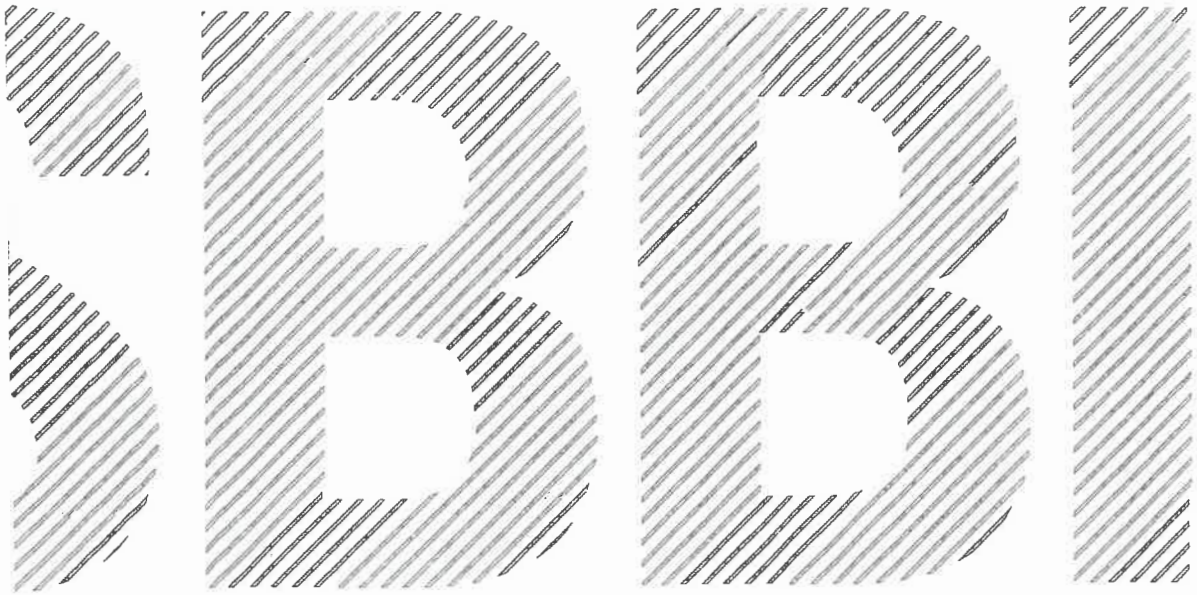

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Business Valuation

One required element of the income approach to company valuation is the discount rate. Under the income approach, cash flows are projected into the future and discounted back to present value using a discount rate reflective of the risk inherent in those cash flows. The income approach is expressed in the following formula:

$$PV_s = \frac{CF_1}{(1+k_s)^1} + \frac{CF_2}{(1+k_s)^2} + \ldots + \frac{CF_i}{(1+k_s)^i}$$

where:

PV_s = the present value of the expected cash flows for company **s**;
CF_i = the dividend or cash flow expected to be received at the end of period **i**; and
k_s = the cost of capital for company **s**.

The discount rate is synonymous with the cost of capital.

While determining the appropriate future cash flow stream is an essential element of the income approach, determining the appropriate discount rate is equally important. Under the income approach, small changes in the discount rate can have a large impact on the ultimate value that is derived.

Table 2-2 is a simple valuation example that illustrates the impact of small changes in the discount rate. In the example, the entity being valued produces cash flows of $1,000 each year in years one through four, and $10,000 in year five. The lower portion of the table shows the values derived from this cash flow stream using different discount rates.

Table 2-2: Valuing Future Cash Flows with Different Discount Rates

Projected Cash Flows ($)

Year 1	Year 2	Year 3	Year 4	Year 5
1,000	1,000	1,000	1,000	10,000

Present Value of Cash Flows ($)

Discount Rate (%)	Year 1	Year 2	Year 3	Year 4	Year 5	Total
10	909	826	751	683	6,209	**9,379**
11	901	812	731	659	5,935	9,037
12	893	797	712	636	5,674	8,712
13	885	783	693	613	5,428	8,402
14	877	769	675	592	5,194	8,107
15	870	756	658	572	4,972	**7,827**

Whether this entity is worth $9,379 using a discount rate of 10 percent or $7,827 using a discount rate of 15 percent may seem trivial. If these values were in thousands or millions of dollars, however, the differences would be significant.

The preceding example focused on values produced from discount rates that are 500 basis points apart. While this may seem extreme, basic assumptions in the determination of the cost of capital can lead to discount rates that are widely divergent. Understanding the assumptions that underlie the discount rate is as important as understanding the assumptions that underlie the cash flows.

Regulatory Proceedings

Even in this era of deregulation, most utilities are regulated to some extent by local government bodies. An appointed commission ensures that the utility, because of its alleged monopolistic power, does not take advantage of its customers and that its investors receive a fair rate of return on their invested capital. One of the most important functions of the commission is to determine an appropriate (often called the "allowed") rate of return. The procedures for setting rates of return for regulated utilities often specify or suggest that the required rate is that which would allow the firm to attract and retain debt and equity capital over the long term.

Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital). In addition, certain regulatory environments may require that shareholders not earn more than the allowed rate of return. If a shareholder does earn more, future rates for the utilities services may be reduced by the regulating body. If the allowed rate of return falls below the cost of capital, regulators may allow a rate increase in order to compensate the investor so that they will on average over time earn the market-required rate of return. Yet other regulatory conditions may require that the allowed rate of return be different from the cost of capital.

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123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 501

Golden Spread Electric Cooperative, Inc.
Lyntegar Electric Cooperative, Inc.
Farmers' Electric Cooperative, Inc.
Lea County Electric Cooperative, Inc.
Central Valley Electric Cooperative, Inc.
Roosevelt County Electric Cooperative, Inc. — Docket No. EL05-19-002

v.

Southwestern Public Service Company

Southwestern Public Service Company — Docket No. ER05-168-001

Issued: April 21, 2008

123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Golden Spread Electric Cooperative, Inc.
Lyntegar Electric Cooperative, Inc.
Farmers' Electric Cooperative, Inc.
Lea County Electric Cooperative, Inc.
Central Valley Electric Cooperative, Inc.
Roosevelt County Electric Cooperative, Inc.

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Southwestern Public Service Company

Southwestern Public Service Company Docket No. ER05-168-001

OPINION NO. 501

OPINION AND ORDER ON INITIAL DECISION

(Issued April 21, 2008)

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I. Introduction

1. This case arises in part out of a complaint, filed on November 2, 2004, by several cooperatives (the Cooperative Customer Group, CCG, or complainants).[1] These cooperatives purchase requirements service from Southwestern Public Service Company (SPS).[2] SPS, a subsidiary of Xcel Energy Inc., is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 386,000 electric customers in portions of Texas and New Mexico, and also operates in Oklahoma and Kansas.

2. The complaint, filed under section 206 of the Federal Power Act (FPA),[3] alleges that SPS has historically violated, and continues to violate, the fuel cost adjustment clause (FCAC) provisions of its wholesale customers' rate schedules and the Commission's FCAC regulations. Complainants assert that SPS may be flowing through

[1] When the complaint was filed, CCG included Golden Spread Electric Cooperative, Inc. (Golden Spread), Lyntegar Electric Cooperative, Inc. (Lyntegar), Farmers' Electric Cooperative, Inc. (Farmers'), Lea County Electric Cooperative, Inc. (Lea County), Central Valley Electric Cooperative, Inc. (Central Valley), and Roosevelt County Electric Cooperative, Inc. (Roosevelt County). However, since that time, Golden Spread and Lyntegar have resolved with SPS all issues except one in a settlement filed on December 3, 2007 (Settlement Agreement). Therefore, in this order, CCG will only include Farmers', Lea County, Central Valley, and Roosevelt County.

[2] All of the cooperatives involved in this proceeding are full requirements customers, except Golden Spread, which is a partial requirements customer.

[3] 16 U.S.C. § 824e (2000).

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its FCAC virtually all energy-related purchased power costs, and that some of the costs are not permissible under the filed rate or the Commission's regulations. Complainants also expressed concern that SPS was not appropriately crediting the FCAC (and as a result, its requirements customers) with the cost associated with incremental fuel when it makes intersystem sales. That is, complainants argue that intersystem sales are opportunity sales and that the intersystem customers should have higher cost incremental fuel attributed to their transactions for purposes of computing the FCAC. They also argue that lower cost energy purchases incurred to meet SPS' requirements customers' needs have been allocated to intersystem sales, resulting in requirements customers subsidizing SPS' marketing function. Complainants asked the Commission to investigate FCAC charges dating back to the last Commission audit of SPS under section 205(f) of the FPA,[4] or at least from 1994. We address the issue of how to treat fuel costs under market-based contracts when determining the FCAC for wholesale requirements customers in section II of this order.

3. The complainants also allege that SPS' cost-based rates for full and partial requirements service are excessive, unjust and unreasonable, and unduly discriminatory or preferential for a number of reasons as explained below.[5] SPS' cost-based rates are addressed in section III of this order.

4. On the same date that CCG filed its complaint against SPS,[6] SPS filed a proposal under section 205 of the FPA[7] to change its FCAC and to make corresponding revisions to SPS' power supply contracts.[8] SPS stated that it filed the revised FCAC to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations,[9] and also to account for expenses and revenues associated with SPS' participation in the Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT). Under the revised FCAC, SPS would collect the net difference between the amounts SPS pays to SPP for transmission losses and the amounts that SPP distributes to

---

[4] *Id.* § 824d(f).

[5] *See e.g.* CCG's April 10, 2006, Initial Brief at Issue I (Cost of Service Issues).

[6] Docket No. EL05-19-000.

[7] 16 U.S.C. § 824d (2000).

[8] Docket No. ER05-168-000. SPS' proposed FCAC that is discussed in section V of this order is contained in the November 2, 2004, filing.

[9] *See* 18 C.F.R. § 35.14 (2007); *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*, Order No. 352, FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

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SPS to compensate it for supplying energy to cover transmission losses. Issues pertaining to SPS' former FCAC are addressed in section IV of this order. Issues pertaining to SPS' proposed FCAC are addressed in section V.

5. On December 21, 2004, the Commission established hearing and settlement judge procedures in response to the CCG complaint, and set a refund effective date of January 1, 2005, for damages arising from the complaint.[10] On December 29, 2004, the Commission accepted and suspended, for a nominal period, subject to refund (also effective January 1, 2005, sixty days following the filing of the FPA section 205 proposal), SPS' proposed changes to the FCAC.[11] The Commission also consolidated SPS' proposed FCAC changes with the proceeding already underway in the complaint case before an administrative law judge (ALJ).

6. On May 24, 2006, the ALJ issued an Initial Decision.[12] Briefs on Exceptions were filed by SPS, CCG,[13] Central Valley, Trial Staff, Occidental Permian Ltd. and Occidental Power Marketing, L.P. (collectively, Occidental), Public Service Company of New Mexico (PNM), and Cap Rock Energy Corporation (Cap Rock) on June 23, 2006. Briefs Opposing Exceptions were filed by SPS, CCG, Trial Staff, Occidental, PNM, and Golden Spread on July 13, 2006.[14]

---

[10] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (order on complaint establishing hearing and settlement judge procedures). In accordance with FPA section 206(b) as it existed at the time of the complaint, the refund effective date in complaint proceedings shall not be earlier than the date sixty days after the filing of a complaint, nor later than five months after the expiration of such sixty-day period. Here the refund effective date is sixty days after the filing of the complaint.

[11] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (order accepting and suspending proposed fuel adjustment clause changes, establishing hearing and settlement judge procedures, and consolidating proceedings).

[12] *Golden Spread Elec. Coop., Inc.*, 115 FERC ¶ 63,043 (2006) (Initial Decision).

[13] As noted above, at the time Briefs on Exceptions and Briefs Opposing Exceptions were filed, CCG included Golden Spread and Lyntegar.

[14] Due to the Settlement Agreement, we will not discuss the briefs of Golden Spread and Occidental in this order.

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7. Between July and November 2007, the parties filed three motions asking the Commission to defer action on the Initial Decision to permit additional time for settlement discussions.[15] The Commission granted all of these motions.

8. On December 3, 2007, SPS submitted a Settlement Agreement on behalf of itself, Golden Spread, Lyntegar, and Occidental (collectively, the Settling Parties). The Settlement Agreement resolves all issues between the Settling Parties except one, which is the issue of the appropriate demand cost allocator for use on the SPS system. On January 18, 2008, the Settlement Judge certified the Settlement Agreement to the Commission as uncontested.[16]

9. On March 14, SPS, Golden Spread, and Lyntegar filed a motion requesting that the Commission promptly approve the Settlement Agreement. PNM, Occidental, Central Valley, Farmers', and Roosevelt County filed answers to the Settling Parties' motion stating that they do not oppose the motion, but request that the Commission also promptly issue an order on the Initial Decision.

10. This order resolves all issues between the non-settling parties. In addition, because the Settlement Agreement does not resolve the demand cost allocator issue, this order also resolves that issue as it applies to both the Settling Parties and the non-settling parties.

11. This order affirms in part, and reverses in part, the Initial Decision. Broadly speaking, the dispute addressed by this order involves intersystem sales and how they relate to the FCAC, a range of cost of service issues associated with SPS' cost-based rates for full and partial requirements service, and SPS' former FCAC and proposed FCAC.

---

[15] On July 17, 2007, SPS and Golden Spread filed a joint motion asking the Commission to defer action on the Initial Decision to permit additional time for settlement discussions. On September 17, 2007, SPS, Golden Spread, Lyntegar, Farmers', Lea County, Central Valley, Roosevelt County, and Cap Rock, filed another joint motion asking the Commission to defer action on the Initial Decision for the same reason. On November 14, 2007, Golden Spread, Lyntegar, and Occidental filed a third joint motion requesting more time to engage in settlement discussions.

[16] *Southwestern Public Service Co.*, 122 FERC ¶ 63,003 (2008). In an order issued contemporaneously with this order, the Commission approved the Settlement Agreement, subject to modification. *Golden Spread Elec. Coop., Inc.*, 123 FERC ¶ 61,054 (2008) (Order Approving Uncontested Partial Settlement Subject to Modifications).

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II. Intersystem Sales and the FCAC

12. The most significant aspect of this case involves how the FCAC operates under section 35.14 of the Commission's regulations with respect to market-based rate transactions. CCG argues that SPS' allocation of average fuel cost for market-based sales impermissibly subsidizes intersystem sales at the expense of native load customers. It is not disputed that SPS' market-based sales contracts provide that SPS recovers the average cost of fuel, not the incremental cost as complainants would prefer.

A. The Commission's Fuel and Purchased Power Cost Adjustment Regulations, 18 C.F.R. § 35.14(a)(2)(v) (2006)[17]

13. Rates for electric service generally have two components; a "demand charge" to recover the utility's fixed (capacity related) costs and an "energy charge" to recover the utility's variable costs, primarily cost of fuel.

14. The energy charge is further composed of two elements. The first element is the "basic energy rate." This recovers the "base cost" of fuel. The basic energy rate must be approved in advance by the Commission. The second element is the "fuel adjustment" charge. This charge is based on a formula designed to recover the difference between the base cost of fuel and the actual cost of fuel incurred over time. A utility's fuel adjustment formula must be approved by the Commission, for it is part of the utility's filed rate. The monthly charge that results from application of the formula, which is an approved rate, thus need not be filed for Commission approval. The fuel adjustment clauses enable utilities to keep their rates in line with the current cost of their fuel without continually having to file for rate increases and decreases.

15. Section 35.14(a)(2) of the Commission's regulations provides in pertinent part as follows:

> 35.14 – Fuel cost and purchased economic power adjustment clauses
> (a)(2) – Fuel and purchased economic power costs shall be the cost of:
> (i)-(iv) – [various costs and charges]
> (v) – *And less* the cost of fossil and nuclear fuel recovered through all intersystem sales. (Emphasis in original).

[17] Unless otherwise stated, all references to section 35.14 are to the 2006 version (in earlier years, subsection (a)(2)(v) was (a)(2)(iv)).

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SPS' FCAC largely tracks the Commission's *pro forma* FCAC. SPS submitted into evidence a sample of its wholesale fuel cost and economic purchased power adjustment clause, which provides in relevant part as follows:

> 2. Fuel costs (*F*), measured in $, shall be the cost of:
>
> (i) fossil and nuclear fuel consumed in Company's own plants . . . .
>
> * * *
>
> (viii) less, the cost of fossil and nuclear fuel and the costs of energy purchases recovered through all inter-system sales.[18]

16. As the Commission has explained before, "[t]he fuel adjustment clause is intended to keep utilities whole with respect to changes in the cost of their fuel. It allows utilities to pass through to their ratepayers increases or decreases in the cost of their fuel, without having to make separate rate filings to reflect each change in fuel cost, and without having to obtain Commission review of each change in fuel cost."[19]

17. The FCAC issues in this proceeding fall into two categories: those raised in the complaint against SPS in Docket No. EL05-19 concerning the SPS FCAC that was in effect prior to the effective date of the proposed FCAC (January 1, 2005) and those in Docket No. ER05-168 concerning the FCAC that SPS proposed in the FPA section 205 filing that is also part of this proceeding.[20] In the following section we address the

---

[18] Ex. SPS-2 at 1-2 (Southwestern Public Service Company FERC Electric Rate Schedule No. 118, First Revised Sheet No. 16).

[19] *Missouri Pub. Serv. Co.*, Opinion No. 327, 48 FERC ¶ 61,011, at 61,078 (1989) (Opinion No. 327) (citing *Fuel Adjustment Clauses in Wholesale Rate Schedule*, Order No. 517, 52 FPC 1304 (1974) (FPC Order No. 517)); *see also Public Utils. Comm'n of California v. FERC*, 254 F.3d 250, 256 n.6 (D.C. Cir. 2001) (citing Opinion No. 327 for proposition that intent of fuel adjustment clause is to keep utilities whole with respect to changes in cost of fuel).

[20] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (order on complaint establishing hearing and settlement judge procedures), *with Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (accepting and suspending proposed FCAC and consolidating with complaint proceeding).

general question of how fuel costs recovered from intersystem sales should be allocated per the FCAC under section 35.14(a)(2)(v) when the intersystem sales are market-based rate transactions.

1. Initial Decision

18. The ALJ concluded that SPS' FCAC practices are not permissible. The ALJ first noted that SPS had a long-standing practice of allocating system average fuel and purchased energy costs to firm system capacity sales.[21] The ALJ further observed that in recent years, as the industry has evolved from cost-based to market-based rates, SPS did not reexamine its practice of allocating system average fuel and purchased energy costs to its capacity sales, regardless of whether such sales were opportunity-type sales made under a market-based tariff or traditional requirements sales made under a cost-based tariff.

19. In finding that the sales in question were intersystem opportunity sales, the ALJ characterized them as having a "lesser status" than native load sales, and the ALJ distinguished the intersystem sales from native load sales in that intersystem opportunity sales do not require the same amount of capacity planning, construction, or maintenance.[22]

20. The ALJ stated that the Commission's policy has been "that opportunity sales are generally priced to reflect incremental fuel cost, so that the risk of recovery would fall upon the utility, not other customers."[23] Recognizing the converse, i.e., that wholesale requirements customers pay the average fuel cost, the ALJ also stated that "the record supports the view that this policy was well understood in the industry, as [Golden Spread's witness] suggested, when he stated that other utilities believed that system average fuel belonged to 'the regulated customers, being native load customers, retail, long-term wholesale, those that are considered native or captive customers within their jurisdiction.'"[24]

21. In response to Trial Staff's argument that wholesale requirements customers do not have a superior claim to service than a non-requirements customer, the ALJ stated that "to charge market-based rate customers system average fuel costs should not bind

---

[21] Initial Decision at P 133 (citing Ex. SPS-12 at 15); *id.* P 146.

[22] *Id.* P 33.

[23] *Id.* P 148.

[24] *Id.* (citing Tr. 962-63 (Wise)).

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non-signatory wholesale customers and the Company's retail customers to subsidize such sales through the FCAC by failing to recover from the opportunity sale customers the real incremental fuel costs associated with the market-based sales."[25] The ALJ referenced *Heartland Energy Services, Inc.*,[26] *Entergy Services, Inc.*,[27] and *Consumers Energy Co.*[28] for the proposition that cost-based requirements customers should not subsidize a utility's market-based activities, and the ALJ also noted that other utilities avoided situations such as the one that SPS entered into.[29]

22. The ALJ concluded that:

> The plain facts are that SPS improved its competitive position in making market-based sales by charging market-based customers lower system average fuel costs, and collected the difference from the Company's cost-based customers, who were forced to cover their own fuel costs and the difference between average costs and the incremental fuel costs associated with the market-based sales.[30]

23. The ALJ directed SPS to make a compliance filing "designed to restore its wholesale customers to the position in which they would have been had they been paying a just and reasonable rate, i.e., one calculated to assign incremental fuel costs to market-based customers from 1999 to 2004."[31]

---

[25] *Id.* P 149.

[26] 68 FERC ¶ 61,223, at 62,062-63 (1994) (prohibiting transfer of benefits from captive customers of a franchised public utility to affiliates and shareholders) (*Heartland*).

[27] 58 FERC ¶ 61,234, at 61,772 (1992) (requiring Entergy to charge at least incremental cost to intersystem customers to avoid subsidizing native load customers) (*Entergy*).

[28] 94 FERC ¶ 61,180, at 61,623 (2001) (directing utility to amend wholesale contracts to credit cost of fuel recovered at the hourly system incremental cost for sales to affiliates, or to make revisions accomplishing the same) (*Consumers*).

[29] Initial Decision at P 149.

[30] *Id.* P 150.

[31] *Id.* P 252.

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2. Briefs on Exception

24. On this issue, SPS disagrees with the ALJ on two general principles. First, SPS argues the ALJ erred in concluding that SPS' contested market-based rate sales were intersystem opportunity sales. Second, SPS argues the ALJ erred in concluding that the incremental fuel and purchased power costs attributable to those market-based sales should be credited against the costs of fuel and purchased power recovered from the CCG members and Cap Rock.[32]

25. SPS contends that the market-based sales at issue were neither opportunity nor intersystem sales. Rather, SPS describes the sales as "firm system capacity sales."[33] SPS argues that among the salient characteristics of these contracts, most were for periods of one year or more, and many of these contracts contained the "standard SPS FCAC." Furthermore, SPS states that many of these contracts were filed with the Commission. Although these contracts were made under SPS' market-based rate authority, SPS asserts that the rates were designed to recover SPS' average imbedded costs. The rates included a negotiated demand charge that was no lower than the demand charge assessed on SPS' cost-based partial requirements customers operating within the SPS control area. The rates also incorporated SPS' standard FCAC mechanism to recover average fuel and purchased power costs, which SPS alleges is the same mechanism used to recover such costs from the CCG members.[34]

26. SPS argues that, based on the Commission's statements in cases such as *Wisconsin Public Power, Inc. v. Wisconsin Power & Light Co.*,[35] the disputed sales should not be classified as opportunity or intersystem sales.[36] Citing *Kentucky Utilities Company*,[37] SPS characterizes opportunity sales as non-firm and for limited terms. SPS describes firm service as being available on an as-needed basis, being continuously available, and being priced on a fully-allocated cost basis. SPS cites *Commonwealth Edison Company* as support for this proposition.[38] SPS argues that the disputed sales are not opportunity

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[32] SPS Brief on Exceptions at 21-42.

[33] *Id.* at 22-23.

[34] *Id.* at 22.

[35] 98 FERC ¶ 61,293, at 62,279 (2002), *reh'g denied*, 104 FERC ¶ 61,244 (2003) (*Wisconsin*).

[36] SPS Brief on Exceptions at 22-28.

[37] 22 FERC ¶ 63,011, at 65,024 (1983).

[38] 21 FERC ¶ 61,096, at 61,294 (1982).

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sales because SPS' sales "were continuously available to the customer from the Company's generation resources, which include capacity purchases made to meet planning reserves," were multi-year sales, and were considered in performing annual system planning.[39] SPS states that "[t]he Presiding Judge's conclusion that the firm system capacity sales made by SPS to neighboring utilities are 'fundamentally different from sales to SPS' cost of service customers' is not well founded."[40]

27. SPS argues that neither its FCAC nor the Commission's fuel clause regulations contemplate the attribution of incremental fuel costs to intersystem sales.[41] SPS states that its FCAC, which is on file with the Commission, provides that SPS shall reduce the fuel and purchased costs that it recovers in monthly FCAC billings by "the cost of fossil and nuclear fuel *recovered through inter-system sales . . . .*"[42] SPS further argues that "there is no basis . . . to impute, attribute or otherwise ascribe to such sales an incremental cost for purposes of making monthly FCAC calculations."[43]

28. SPS next argues that the Initial Decision violates the filed rate doctrine by retroactively amending SPS' filed FCAC provisions.[44] Specifically, SPS invokes the filed rate doctrine in response to the ALJ's order that SPS "restore its wholesale customers to the position in which they would have been had they been paying a just and reasonable rate, i.e., one calculated to assign incremental fuel costs to market-based rate customers from 1999 to 2004."[45] SPS states that FPA section 206(b)[46] limits the Commission to ordering prospective relief, which may take effect no earlier than the

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[39] SPS Brief on Exceptions at 24. SPS also cites Ex. CCG-8, CRE-32, and Tr. at 1042:5-9 in support of its argument that it plans for these intersystem sales.

[40] *Id.* at 27.

[41] *Id.* at 28-29.

[42] *Id.* at 28 (emphasis in original).

[43] *Id.* at 29.

[44] *See id.* at 30-32; *see also id.* at 37-41 (asserting that Initial Decision constitutes impermissible collateral attack on SPS' filed rates).

[45] *Id.* at 30 (quoting Initial Decision at P 252). As stated above, the Commission's order on setting the complaint for hearing, *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004), established January 1, 2005, as the refund effective date pursuant to FPA section 206.

[46] 16 U.S.C. § 824e(b) (2000).

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refund effective date established when the complaint proceeding begins.[47] SPS also argues that rates established in power sales contracts filed with and accepted by the Commission are binding on the parties even when it is alleged that the selling utility committed fraud on the purchaser.[48]

29. SPS states that the average cost energy rates were the appropriate basis for pricing the disputed sales.[49] SPS argues that the Commission has approved the sale of firm energy priced on the basis of average system energy costs when the transaction was labeled an opportunity sale, but the sale was firm in nature.[50]

30. SPS also argues that nothing in the power sales agreements, under which SPS serves its wholesale requirements customers, gives them preference rights to SPS' most efficient energy production.[51]

31. Trial Staff argues that SPS was correct in attributing average costs to long-term market-based sales.[52] Specifically, Trial Staff focuses on whether sales for more than one year should be called opportunity sales and treated the same as short-term opportunity sales of one year or less.[53] Trial Staff also argues that "[t]he real problem is that SPS' FCAC practices become less objectionable, the longer the term of the long-term contract, to the extent that SPS would be planning, acquiring, constructing and operating capacity and energy to meet its system-wide load requirements, including these long-term sales."[54] Thus, Trial Staff concludes that the ALJ should have approved of SPS' charging of average fuel cost to long-term market-based rate transactions.

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[47] SPS Brief on Exceptions at 30-31.

[48] *Id.* at 31 (citing *Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251-52 (1951)).

[49] *Id.* at 32-37.

[50] *Id.* at 33 (citing *Public Serv. Co. of New Mexico*, 43 FERC ¶ 61,469, at 62,145, *reh'g denied*, 45 FERC ¶ 61,034 (1988).

[51] *Id.* at 41-42.

[52] Trial Staff Brief on Exceptions at 18-31.

[53] *Id.* at 19.

[54] *Id.* at 19-20.

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3. Briefs Opposing Exceptions

32. CCG argues that the Initial Decision correctly finds that incremental fuel costs should be attributed to SPS' market-based sales.[55] CCG further states that SPS should be required to recalculate the FCAC billings to account differently for SPS' intersystem market-based sales, and that the Commission is permitted to do this under the filed rate doctrine.[56] According to CCG, the Commission has stated that whenever a public utility acts inconsistently with Commission-filed tariffs or with specific requirements in its rate authorizations, the Commission may order refunds to rectify such action.[57] CCG further argues that such refunds are not retroactive ratemaking, but rather serve to ensure that only the filed rate is charged. With formula rates such as the FCAC, argues CCG, the formula itself is the filed rate, and consequently any misapplication of it is a violation of the CCG members' filed rates which the Commission can and should remedy.[58] CCG accordingly asks the Commission to affirm the ALJ and award refunds.[59]

33. CCG states that SPS' sales at issue involve "improper, coerced subsidization by SPS' native load" and that the ALJ properly decided that the policy of protecting wholesale customers from subsidization is an important principle that should be applied here.[60] CCG argues that the filed rate doctrine does not protect SPS because SPS never obtained authorization to engage in a new pricing scheme affecting market-based rate sales that, in turn, could modify the formula applied to cost-of-service based customers.[61]

34. CCG illustrates a distinction between long-standing cost-of-service customers and market-based customers by arguing that CCG and SPS have a regulatory compact to serve and receive service at cost-based rates, as well as the corollary obligation to pay for

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[55] CCG Brief on Exceptions at 19-24.

[56] CCG Brief Opposing Exceptions at 29-34.

[57] *Id.* at 9 (citing *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 96 FERC ¶ 61,120, at 61,508 (2001); *Washington Water Power Co.*, 83 FERC ¶ 61,282, at 62,169 (1998)).

[58] CCG Brief Opposing Exceptions at 9.

[59] *Id.* at 29-34.

[60] *Id.* at 20.

[61] *Id.* at 24-25.

embedded capacity resources over the life of those resources.[62] CCG notes that this compact substantially predates the advent of SPS' market-based rate authority in 1995.[63]

35. PNM argues that "[t]he basic problem with the paradigm advanced by SPS and Staff is that under their theory, the terms of SPS' market-based contracts would control the manner in which the Commission applies its regulations governing automatic recovery of fuel costs. If this is so . . . the amount of fuel costs billed under the market-based contract would control, no matter how little such amounts contributed to recovery of actual fuel costs."[64] PNM also argues that SPS' cost-of-service customers were not on notice of SPS' FCAC practice.[65]

4. Commission Determination

36. Given that SPS' FCAC largely tracks section 35.14 of the Commission's regulations, a review of that section is instructive in understanding how SPS' FCAC should be interpreted. When section 35.14 of the Commission's regulations was changed to roughly its present form in 1974 (as otherwise modified since), the Federal Power Commission (FPC) explained that "the purpose of this fuel cost adjustment clause is to keep the utilities whole with regard to changes in the fuel costs per [kWh] sold" by "pass[ing] on to customers the increases or decreases in the fuel costs actually incurred."[66]

37. In order to calculate the fuel cost for native load customers under section 35.14, a utility first computes the fuel cost for all kWh sold, whether to native load customers or intersystem customers.[67] The utility then deducts from the total fuel cost the cost of fuel recovered through intersystem sales.[68] Native load customers pay the remainder. This

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[62] *Id.* at 28-29.

[63] *Id.*

[64] PNM Brief Opposing Exceptions at 31.

[65] *Id.* at 29; *see generally id.* at 28-32.

[66] FPC Order No. 517, 52 FPC 1304, 1305-06; *accord Pennsylvania Power & Light Co.*, Opinion No. 34, 6 FERC ¶ 61,036, at 61,078 (1979) (*Pennsylvania P&L*).

[67] *See, e.g.*, *Pennsylvania P&L*, 6 FERC ¶ 61,036 at 61,077.

[68] *Id.* (explaining that this prevents a utility from recovering from its native load customer fuel costs recovered elsewhere).

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"ensures that wholesale customers will not pay for fuel costs already paid for by the intersystem customers."[69]

38. In the past, most utilities were vertically integrated entities that generated, transmitted, and distributed energy to customers in a defined region, known as the utility's native load. Those customers paid for the construction and maintenance of the utility's infrastructure and, in return, the utility served that native load.

39. At times, however, a utility may have available excess generation not already committed to native load customers, providing the utility with an opportunity to sell this capacity to buyers outside its home area. These sales are called opportunity sales or intersystem sales. Duration is not necessarily the determining factor in distinguishing opportunity sales from wholesale requirements sales. Opportunity sales "are simply transactions that are entered into from time to time for . . . an immediate economic benefit reason."[70]

40. In *Minnesota Power & Light Co.*, the Commission stated that in considering how to apply the fuel cost of intersystem sales to the requirements customers' FCACs, requirements customers "are credited with the cost of fuel recovered from the off-system customer."[71] In that case, the Commission also explained that the "[u]tilities generally price the fuel component of intersystem sales on the basis of the cost of the incremental fuel used in meeting intersystem load. Pricing an intersystem sale by reference to the incremental fuel cost assures that the requirements customers pay no more than they would have paid had the off-system sale never occurred."[72]

41. The Commission has clearly sought to prevent the subsidization of shareholders at the expense of captive customers.[73] It would be unreasonable for SPS' intersystem

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[69] *Id.* at 61,079. The total amount a utility can collect under the FCAC is limited to the amount spent; the Commission explained that "[w]hile we believe that a utility should be made 'whole for increased fuel costs,' we do not believe that a utility should be made whole and plus some." *Id.*

[70] Tr. at 284:19-21 (Daniel).

[71] 47 FERC ¶ 61,064, at 61,184 (1989) (denying petition for declaratory order that it is just and reasonable to assign to intersystem sales lower cost fuel than to requirements customers, but also stating that such an assignment is not *per se* unjust and unreasonable).

[72] *Id.* at 61,183 n.2; *see also id.* at 61,184.

[73] *See, e.g.*, *Heartland*, 68 FERC at 62,062-63 (prohibiting transfer of benefits from captive customers of a franchised public utility to affiliates and shareholders).

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customers to be subsidized by wholesale requirements customers through an FCAC mechanism based on average fuel cost. Preventing such subsidization was the original reason for requiring that utilities price opportunity sales at a price that, at a minimum, made wholesale requirements customers economically indifferent to the sales.

42. In this case, the Commission must consider the workings of a market-based intersystem sale on a FCAC. Market-based rate transactions may take many forms: prices can be fixed by the contract, based on an index, or derived by some other formula. By definition, such prices may have no basis in actual cost.[74] Consequently, fuel cost must be imputed for these transactions for purposes of the utility's fuel cost clause.

43. The Commission finds that because the market-based intersystem transactions do not necessarily have a basis in actual cost, and to avoid the possibility of subsidization of these transactions by the wholesale requirements customers, the Commission must impute an appropriate fuel rate to the fuel cost calculation in order to avoid native load customers overpaying as a result of intersystem transactions under market-based rate contracts. In reaching this conclusion, the Commission recognizes that the FCAC in SPS' cost-based contracts with respect to fuel costs for market-based intersystem sales may not have been entirely clear.

44. Imputing the incremental cost of fuel to intersystem transactions assures that native load customers pay no more for fuel than they would have paid had the intersystem sale not occurred. To impute something different from incremental costs as a surrogate for the actual fuel cost could allow market-based rate sellers to include an artificially low fuel cost into their market-based rate contracts. Imputing an artificially low fuel cost would result in unjust and unreasonable subsidization of intersystem sales by requirements customers, which is contrary to the intent of the fuel cost clause.[75]

45. Attributing incremental fuel cost is consistent with the only market-based rate case that addressed this subsidizing effect. In *Entergy Services, Inc.*,[76] the Commission acknowledged that there is "no requirement [that the utility, when making off-system

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[74] In the instant proceeding, there is no dispute that SPS' market-based contracts provide for average fuel costs. But the specification of costs in a market-based contract is not determinative for purposes of the current issue, as explained below.

[75] Because the Commission does not review fuel costs in market-based rate contracts, parties could set the fuel cost at any price, or even at zero, which would result in requirements customers compensating the utility for *all* of the utility's fuel costs incurred for sales to others.

[76] 58 FERC ¶ 61,234 (*Entergy*).

sales] sell power and energy . . . at rates that would recover at least its system incremental costs."[77] But to protect wholesale customers who had FCACs in that case, the Commission ordered Entergy to incorporate a floor into the relevant rate schedule equal to the incremental costs incurred to provide the service.[78] The same principles of protecting wholesale requirements customers from an unjust subsidization as applied in *Entergy* apply here.

46. In *Consumers Energy Company*,[79] the Commission addressed the potential for captive wholesale customers to subsidize an affiliate sale because the fuel cost clause excluded sales that Consumers made to an affiliate. The Commission found that the amounts collected by Consumers from its affiliates would have been insufficient to cover the incremental cost of the sales. Recognizing the potential for improper subsidization by captive customers, the Commission directed Consumers to amend its contracts to credit the cost of fuel recovered at the incremental cost or otherwise accomplish the same objective.

47. In the instant proceeding, for market-based rate transactions, SPS' prices are limited by competition in lieu of cost-based regulation. If SPS or any other seller wishes to include a fuel price in its market-based contract, that price may be defined as average (as SPS so defined), indexed, incremental, or in any other manner. The fact that at least some of these contracts were filed with the Commission and accepted for filing is not germane because, as we stress here, the Commission is not seeking to change the contract language regarding fuel costs in market-based contracts, if fuel costs are even addressed at all. The Commission is simply directing here that, in order to avoid subsidization, the incremental cost of fuel for these market-based intersystem sales must be flowed through the FCAC.[80]

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[77] *Id.* at 61,772.

[78] *Id.*

[79] 94 FERC ¶ 61,180 (*Consumers*).

[80] The Commission notes that it may be appropriate to allow a cost of fuel other than the incremental cost to be attributed to market-based intersystem sales where the utility provides clear evidence that it planned and constructed its system or made purchases specifically to serve particular market-based intersystem transactions. However, SPS has failed to provide any such evidence here. Instead, it has provided little more than a general statement that it engaged in such plans (Tr. 1042:5-9 (Diller)), and several load forecast charts that do not make clear what planning, if any, was done to support intersystem sales (Ex. CCG-8 and CRE-32). We are not convinced that such

(continued…)

48. Consistent with this finding, SPS itself appears to have questioned the appropriate cost treatment for market-based intersystem sales transactions. As discussed by the ALJ in the Initial Decision,[81] a former SPS employee who testified for Golden Spread[82] stated that, when he worked at SPS, he had discussions with utilities such as Oklahoma Gas & Electric and other companies in the Southwest Power Pool about utilities not offering system capacity with system fuel costs due to "regulatory risk."[83] According to this witness, whose duties varied at SPS but who described himself as "basically . . . a bulk power sales manager or representative that conducted sales negotiations [with] various wholesale . . . power purchasing entities,"[84] the regulatory risk was:

> the concern . . . that the system average fuel really belongs to the regulated customers, being native load customers, retail, long-term wholesale, those that are considered native or captive customers within their jurisdictions. So they were

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evidence demonstrates that SPS engaged in planning specifically to support its intersystem transactions.

[81] Initial Decision at P 148.

[82] Though Golden Spread settled with SPS and is not a party to the issue discussed in this section of the order, the testimony of Golden Spread's witness remains a part of the record, and as such, the Commission relied upon this testimony in making its determination.

[83] Initial Decision at P 148 (discussing the record supporting the view that opportunity sales are generally priced to reflect incremental fuel cost and citing testimony sponsored by Golden Spread that this was well-understood in the industry). *See generally* Tr. 959-66 (Wise) (redirect examination of Golden Spread witness Wise, attesting that SPS was aware of regulatory risk in offering wholesale system sales at system average fuel cost).

[84] Tr. 957:17-19 (Wise). This witness described his career at SPS more fully in testimony contained in Exhibit GSL-26 at 2-3. His positions at SPS included: Statistician; Supervisor, Market Research; Competitive Analyst; Strategic Analyst; and Regional Power Sales Manager. Ex. GSL-26 at 2-3. In his capacity as Regional Power Sales Manager, this witness states that he was "responsible for analyzing markets and developing and negotiating significant power contracts . . . including: energy, capacity, transmission and ancillary services." *Id.* He further states that he worked with electric cooperatives, municipal utilities and investor owned utilities within SPP, Electric Reliability Council of Texas, and the Northwest Power Pool. *Id.* at 3.

> very concerned, and they said they were frankly surprised that SPS was willing to offer wholesale system sales at system average fuel.[85]

The former SPS manager further testified that "the discussion about system average fuel was well known within the company . . . and it was well known throughout the company . . . there was a potential to have a regulatory treatment that was unfavorable due to it."[86] In this regard, this witness testified that SPS' wholesale power business

> included the regulatory folks . . . and the legal folks in Denver. They were a part of the line of individuals we had to get approvals for to sign any of these contracts. So they were fully aware of all of the conditions . . . .[87]

49. For the reasons discussed in the following section of this order (Time Period Concerning Historical FCAC Charges), the Commission concludes that refunds will be ordered beginning on January 1, 2005, the refund-effective date established in the December 21, 2004, order setting the complaint for hearing,[88] and SPS will be required to implement the FCAC as instructed herein.[89]

B. Time Period Concerning Historical FCAC Charges[90]

1. Initial Decision

50. The ALJ determined that the relevant period for considering the FCAC is from 1999 forward.[91] The ALJ found that FCAC implementation practices became questionable beginning in 1999, after the Commission implemented open access and market-based rate sales increased. The ALJ observed that while market participants had no basis to complain about the FCAC prior to 1999, beginning in 1999, SPS was under a

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[85] Tr. at 962:23-25 through 963:1-5 (Wise). This witness's title at Golden Spread is "Manager, Operations." Ex. GSL-26 at 1:5-6.

[86] *Id.* at 963:11-18 (Wise).

[87] *Id.* at 964:1-5 (Wise).

[88] *Golden Spread Elec. Coop.*, 109 FERC ¶ 61,321 (2004).

[89] Because the Commission is ordering refunds effective January 1, 2005, we need not address SPS' argument that contracts are binding on parties even when fraud is alleged.

[90] Initial Decision at P 120-25 (Issue II.A.1).

[91] *Id.* P 125.

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duty to examine its FCAC implementation practices due to changed market conditions. Therefore, the ALJ determined that SPS would owe refunds for a period beginning in 1999 and ending in 2004.

2. Briefs on Exception

51. SPS argues the ALJ erred because law and equity demand that a decision granting refunds should only be given prospective effect. SPS contends neither SPS nor the Commission has the authority to modify SPS' contracts with SPS' market-based wholesale customers retroactively to provide for the recovery of incremental costs.[92]

3. Commission Determination

52. Sections 205 and 206 of the FPA are the statutory foundation for the filed rate doctrine and the rule against retroactive ratemaking. According to section 205(c), all rates must be on file with the Commission: "Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate . . . schedules showing all rates and charges . . . subject to the jurisdiction of the Commission . . . ."[93] The Commission has determined that utilities engaging in market-based sales must file a tariff with the Commission so stating, but components of the price need not be broken out in the tariff. Instead, information relating to transactions must be filed in Electric Quarterly Reports,[94] and the contracts remain jurisdictional without having to be filed with us.[95]

53. In the instant proceeding, both as to SPS' prior FCAC that is the subject of a complaint and as to the FCAC that SPS proposes in its FPA section 205 filing, SPS

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[92] SPS Brief on Exceptions at 9-10.

[93] 16 U.S.C. § 824d(c) (2000).

[94] 18 C.F.R. § 35.10b (2007) (directing public utilities to file updated Electric Quarterly Reports, which must be prepared in conformance with the Commission's guidance posted and available on the Commission's website).

[95] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, at P 223 (stating that Electric Quarterly Reports are designed to satisfy the FPA section 205(c) requirement that public utilities file jurisdictional rates and charges with the Commission), *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334 (2003).

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flowed through (and proposes to continue to flow through) its FCAC the amount of money recovered for fuel for its market-based sales based on the average cost. The Commission may take retroactive refund action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs, but SPS' FCAC is ambiguous on the issue in dispute.[96] Following consideration of all of the evidence presented, the Commission has concluded above that in order to avoid wholesale requirements customers subsidizing intersystem sales, SPS' FCAC should be construed as requiring SPS to attribute incremental costs for purposes of the FCAC.[97] However, because the interpretation of the FCACs contained within SPS' contracts with respect to such attribution may not have been clear prior to the institution of these proceedings, the Commission will apply the clarification of FCACs to take effect as of the refund effective date established in these proceedings. We note that "the breadth of agency discretion is, if anything, at zenith when the action assailed relates primarily . . . to the fashioning of policies, remedies and sanctions . . . ."[98] Accordingly, SPS is directed to make refunds starting with the refund effective date, January 1, 2005,[99] and to apply the FCAC as directed herein on a prospective basis.

III. Cost of Service

54. In its original complaint, CCG argues that SPS' full requirements and partial requirements rates for the period January 1, 2005 to July 1, 2006[100] are unjust and unreasonable and are unduly discriminatory and/or preferential.[101] CCG cites its

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[96] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (June 21, 2007), *clarifying order*, 122 FERC ¶ 61,260 (2007) (stating that the Commission is authorized to order potential retroactive refunds for tariff violations).

[97] *See supra* P 43, 49.

[98] *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) (internal citation omitted).

[99] *See Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (establishing refund effective date in Docket No. EL05-19-000 under FPA section 206).

[100] In Docket No. ER06-274-000, SPS filed new rates for its full and partial requirements customers that were set for hearing and made effective July 1, 2006, subject to refund. *See Southwestern Pub. Serv. Co.*, 114 FERC ¶ 61,091 (2006). That docket has not been consolidated with the instant proceeding.

[101] CCG Complaint at P 10-16.

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allocated cost-of-service analysis in arguing that SPS' current demand and energy charges and the associated revenues in the aggregate and as applicable to each of the cooperatives' members exceed prudently incurred and properly allocated costs of providing requirements power supply service. CCG concludes that SPS' "overcharges . . . will result in higher rates for the retail consumers."[102] CCG also asserts that SPS data submissions to the Commission contain inconsistencies, and that these submissions lack detail; the result, CCG claims, is that they cannot confirm the proper values to be used in a cost of service analysis. CCG also alleges that SPS' parent company, Xcel Energy Inc., allocates excessive costs to SPS. Based on the allegations raised in the complaint, the Commission set the matter for hearing and settlement judge procedures.

A. Rate of Return[103]

1. Initial Decision

55. As explained by the ALJ, the determination of a just and reasonable return on equity (ROE) is governed by two standards: (1) the rate must be sufficient to allow the regulated entity to maintain its financial integrity and to allow the utility to maintain its credit and attract investment capital; and (2) the rate must be commensurate with returns on investments in enterprises that have a corresponding risk.[104]

56. The ALJ also stated that the discounted cash flow (DCF) methodology has been favored by the Commission, and that the Commission has expressed a preference for using current market data to develop an electric utility's ROE.[105] When, as in this case, the rate under consideration is "locked-in" (the rate being litigated has been superseded or is otherwise no longer in effect), the Commission updates the equity allowance for the

[102] *Id.* P 10.

[103] Initial Decision at P 80-107 (Issue I.*I*).

[104] *Id.* P 80 (citing *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n,* 262 U.S. 679, 693 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)).

[105] *Id.* P 80.

locked-in period based on the change in average yields on ten-year constant maturity U.S. Treasury bonds.[106]

57. The ALJ accepted Trial Staff's proxy group.[107] Using that proxy group, the ALJ determined that 9.64 percent is the just and reasonable ROE for SPS. In making this determination the ALJ used 9.20 percent, the median ROE of Trial Staff's proxy group, as a base and added seven basis points as a flotation adjustment for an ROE of 9.27 percent.[108] The ALJ then added 37 basis points to account for interest rate risk, for a total ROE of 9.64.[109]

2. Briefs on Exception

58. SPS argues[110] that the ALJ's reliance on Trial Staff's analysis using the median value for the zone of reasonableness was incorrect because the Commission's recent orders relating to ROE employ the midpoint, not the median, in setting the ROE for electric utilities.[111] SPS also argues that the ALJ compounded this error by adopting the ROE at the median for the zone of reasonableness established by the high and low returns of Trial Staff's four proxy companies. SPS claims that the ROE should be placed in the upper half of the zone of reasonableness because three of the four companies in Trial Staff's analysis have higher credit and bond ratings than SPS and therefore SPS presents

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[106] *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009 (1996) (explaining "locked-in" rates); Initial Decision at 104 (citing Commission practice of updating return on equity).

[107] Initial Decision at P 104-105.

[108] Initial Decision at P 96 (description of Trial Staff's analysis); *see also id.* P 96-103 (discussing Trial Staff's arguments on ROE).

[109] *Id.* P 104.

[110] SPS Brief on Exceptions at 71-75.

[111] SPS Brief on Exceptions at 72. SPS cites *Consumers Energy Company*, 98 FERC ¶ 61,333, at 62,416 (2002), and *Southern California Edison Company*, Opinion No. 445, 92 FERC ¶ 61,070 (2000) (*Southern California Edison*), as support for using the midpoint. The Commission notes here that the midpoint of all the estimates of ROE of a proxy group is the average of the highest and lowest estimated ROE of all members of the group. The median is that point within the zone of reasonableness where half the returns have a higher value and half the returns have a lower value. The mean, or average, is the sum of the estimates of each member of the proxy group, divided by the number of estimates.

a greater financial risk.[112] SPS states that it is seen by the financial community as a company that presents relatively more risk than Trial Staff's proxy companies do, and that when faced with similar facts in *Southern California Edison Co.*,[113] the Commission found that the ROE should be above the midpoint of returns indicated for the comparison group.[114] SPS argues that the appropriate ROE in the instant case should be 10.65 percent.[115] SPS also claims that this should be adjusted upward for the increase in the 10-year constant maturity Treasury bonds for the period ending June 30, 2006, the end of the period for the rates at issue in this case.[116]

59. CCG argues the ALJ should not have rejected its proxy group based on a determination that one of the proxy group companies did not accurately reflect the risks of SPS, nor should the ALJ have concluded that a three company proxy group was insufficient to judge return in a DCF analysis. CCG also claims the ALJ should have used the Commission's long-standing methodology for locked-in rates rather than a method used for open-ended periods.[117] CCG states that it does not object to adjusting the ROE *per se*; however, it highlights the fact that the rates at issue here are for a locked-in period.[118] CCG cites several cases in support of its position that "in updating an ROE applicable to a locked-in period, the appropriate inquiry is to compare the average yield on ten-year constant maturity Treasury bonds in the period used to establish the ROE to the average yield on such bonds for the entire locked-in period."[119] Then, CCG states, the Commission should adjust the locked-in period ROE for any difference found, if the resulting ROE is still within the zone of reasonableness established in the

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[112] SPS Brief on Exceptions at 73.

[113] 92 FERC ¶ 61,070.

[114] SPS Brief on Exceptions at 73-74.

[115] *Id.* at 74-75.

[116] *Id.* at 75 n.74.

[117] CCG Brief on Exceptions at 36-39.

[118] *Id.* at 37.

[119] *Id.* at 37 (citing *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009-10 (1996); *Indiana Mun. Distrib. Assn. v. Indiana Michigan Power Co.*, Opinion No. 373, 59 FERC ¶ 61,260, at 61,978 (1992); *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363-A, 57 FERC ¶ 61,200, at 61,371-72 (1991); *Pacific Gas & Elec. Co.*, Opinion No. 356, 53 FERC ¶ 61,146, at 61,537-38 (1990)).

record.[120] CCG contends following the locked-in method results in an adjustment of 6 basis points rather than 37, with the resulting ROE being 9.33 percent (9.27 + .06).[121]

3. Briefs Opposing Exceptions

60. CCG and Trial Staff object to SPS' claim that Commission policy is to use the midpoint to set the ROE for a single utility. CCG and Trial Staff cite the Commission's discussion in *Midwest Independent Transmission System Operator, Inc*.[122] as the correct policy: i.e., that the median is the appropriate measure of central tendency of a single utility. Further, CCG and Trial Staff argue that the ALJ was correct in rejecting SPS' request to place the ROE in the upper end of the range of the zone of reasonableness. CCG argues that SPS' claims of higher risk based on three of four companies having higher risk credit and bond ratings does not justify a higher ROE. This is because, in total, SPS is no greater risk than the proxy group based on an analysis of multiple credit risk factors. CCG highlights Staff's testimony that addressed three indicators of risk and concluded that SPS and the proxy group were equal in risk.[123] In its brief opposing exceptions, Trial Staff asserts that while three of the four companies in its proxy group had higher S&P Corporate Credit Ratings, SPS ignored other important risk factors. These factors are: (1) the *Value Line* Safety Rank, a comprehensive measurement of risk derived from the volatility of the stock as measured by its index of price stability relative to 1,700 other stocks over the past five years; (2) *Value Line's* Financial Strength rating of the company; and (3) S&P's Business Profile comparisons. S&P's Business Profile is a rating system that measures a company's business risk relative to an overall utility industry business risk profile.[124] Trial Staff's analysis indicated that its proxy group members and SPS' parent, Xcel Energy Inc., all had a Safety Rank of 2. In addition, SPS' S&P Business Profile number was 5 (on a scale of 1 to 10, where 1 is least risky and 10 is most risky) as opposed to Trial Staff's proxy group average of 5.5.[125] Therefore, Trial Staff argues, SPS poses no greater risk than the proxy group and SPS should be placed in the median of the zone of reasonableness.

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[120] *Id.* at 37.

[121] *Id.* at 39.

[122] *Midwest Indep. Transmission Sys. Operator, Inc*., Order on Remand, 106 FERC ¶ 61,302, at P 12 (2004) (*Midwest ISO*).

[123] CCG Brief Opposing Exceptions at 63-66.

[124] Trial Staff Brief Opposing Exceptions at 23-25.

[125] *Id.*

61. SPS argues that the ALJ's decision rejecting CCG's proxy group was reasonable, because Energy East did not face the same business risks as SPS and therefore was not a reliable basis for an ROE determination.

4. Commission Determination

62. Based on the record in this case, we find the just and reasonable ROE to be 9.33 percent for the period beginning January 1, 2005 and ending July 1, 2006. The Commission affirms the ALJ's determination to use Trial Staff's proxy group.[126] We also affirm the ALJ's use of the median value for the zone of reasonableness to determine the just and reasonable ROE. However, as discussed below, we reverse the ALJ's finding that a 37 basis point interest rate adjustment is appropriate.

63. When deriving the ROE for an individual utility facing average risk, the Commission has held that the median best represents the central tendency in a proxy group with a skewed distribution of returns.[127] In *Midwest ISO*[128] the Commission contrasted the formula for deriving the ROE for an individual utility versus the formula for deriving the ROE for a diverse group of utilities included in the Midwest ISO.

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[126] Both Trial Staff's proxy group and CCG's proxy group result in a 9.27 percent ROE. Initial Decision at P 89 and P 96. The Commission also agrees with the ALJ's decision to reject CCG's proxy group based upon its inclusion of Energy East, because the company may not accurately reflect SPS' risks. *Id.* P 107. While a larger group is generally desirable, the group cannot include companies that are not reflective of the subject companies. Using Trial Staff's proxy group is thus preferable to CCG's proxy group because when two groups' risk profiles are interchangeable, the larger group is statistically preferable. Trial Staff's proxy group is also more representative than SPS', which the ALJ found, *inter alia*, included companies with business and related risks that are significantly different from SPS' regulated utility business and wholesale electric service. *Id*. P 106. Finally, the Commission agrees with the ALJ's rejection of SPS' proxy group because of the inclusion of Constellation, which was in the midst of merger activity at the relevant time. *Id.* P 106.

[127] *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002). However, as discussed further below, to the extent that the Commission determines that an applicant is not of average risk vis-à-vis the proxy group, then the Commission's *Southern California Edison* precedent would apply to the determination of the appropriate ROE within the range of reasonableness.

[128] 106 FERC ¶ 61,302 at P 10.

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> Because the ROE in this case will apply to a diverse group of companies, the entire range of results yielded by the subset is relevant here. Thus, we find that using the midpoint is the most appropriate measure for determining a single ROE for all Midwest ISO [transmission operators], since it fully considers that range. Selecting the most refined measure of central tendency, as might be achieved with use of the median, is not the Commission's goal in this case, given that we are not selecting a ROE for a single utility of average risk.[129]

64. Here, we are determining the just and reasonable ROE for a single utility of average risk and find the median to be appropriate for setting the ROE. In *Transcontinental Gas Pipe Line Corp.*,[130] the Commission determined that setting the ROE at the median of the zone of reasonableness lessens the impact of any single proxy company whose ROE is atypically high or low. While there are no concerns of extremes here, using the median also has the advantage of taking into account more of the companies in a proxy group rather than only those at the top and bottom. We decline to place SPS in the upper half of the zone of reasonableness because we conclude, based on the S&P Safety Rank and Business Profile factors, SPS does not have any higher risk than the proxy group, despite SPS' arguments to the contrary.[131] SPS cites *Southern California Edison*, a case in which the Commission placed the utility in the upper half of the zone of reasonableness because it found the company to be more risky than the proxy group.[132] Unlike in *Southern California Edison*, here we find that SPS is not more risky than the proxy group. Accordingly, we affirm the use of the median in establishing the ROE for SPS.

65. We reverse the ALJ's finding that there should be a 37 basis point interest rate adjustment. Instead, the adjustment should be 6 basis points, because the rates at issue here are for a locked-in period. Therefore, the ROE should be 9.33 percent (9.27 plus 6 basis points). As CCG correctly noted, where the rate under consideration is "locked-in" (that is, the rate being litigated has been superseded or is otherwise no longer in effect),[133]

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[129] *Midwest ISO*, 106 FERC ¶ 61,302 at P 10.

[130] 84 FERC ¶ 61,084, *aff'd* Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

[131] Trial Staff Brief Opposing Exceptions at 23-25.

[132] *Southern California Edison*, 92 FERC ¶ 61,070, at 61,266 (2000) ("[W]e find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group").

[133] As noted, the rates at issue here are for the locked-in period from January 1, 2005 to July 1, 2006.

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the Commission updates the equity allowance for the locked-in period based on the change in average yields on ten-year constant maturity U.S. Treasury bonds.[134] Instead of following the Commission's methodology for adjustments applicable to locked-in period rates, the ALJ used the Commission's method for updating based on open-ended rates. This was inconsistent with Commission policy, as the rates at issue here were for a locked-in period. Accordingly, we adopt the adjustment required by Commission precedent for locked-in rates, 6 basis points instead of 37 basis points.

B. Coincident Peak Basis (3 CP v. 12 CP)[135]

66. Demand allocation refers to the method of apportioning fixed capacity costs among customer classes. The Commission typically uses a coincident peak method to allocate demand costs, in which demand costs are allocated based on the customer class' demand at the time of (coincident with) the system peak demand.[136] The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in twelve months (12 CP). A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year. A summer (or winter) peaking company would more typically allocate demand on a 3 CP basis, which assumes demand will peak during the three peak usage months.

1. Initial Decision

67. The ALJ concluded that SPS remains a 3 CP system,[137] not a 12 CP system as Cap Rock, SPS, and CCG propose. The ALJ cited *Louisiana Power & Light Co.*,[138] in

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[134] *E.g.*, *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009-10 (1996).

[135] Initial Decision at P 10-24 (Issue I.A). We note that the issue of the Coincident Peak Basis is the sole issue that the Settling Parties did not resolve in the Settlement Agreement. Therefore, this portion of the order applies to both the Settling Parties and non-settling parties.

[136] *See generally Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,199-203 (1981), *aff'd in relevant part*, Opinion No. 185, 24 FERC ¶ 61,199 (1983) (*Delmarva Initial Decision*) (discussing method of demand cost allocation).

[137] *Cf. Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341, at 61,589-591, *reh'g denied*, 23 FERC ¶ 61,406 (1983) (Opinion No. 162) (affirming that SPS is a 3 CP system); *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC

(continued…)

rejecting calls for changing SPS' demand allocation method. *Louisiana P&L*, the ALJ explained, states that the demand allocation method should not be changed except when there are changed circumstances or a change in policy.[139] The ALJ concluded that the data suggest modest changes but not "major shifts" in the load curve.[140] The ALJ further observed that one of the factors that may have caused the movement in the direction of a flatter demand curve – the increase in intersystem sales caused by the availability of excess power due to the shift of Golden Spread to a partial requirements customer – has run its course.[141] Moreover, the ALJ found that one cannot assume the continuation of whatever flattening of the demand curve occurred.[142]

2. Briefs on Exceptions

68. CCG,[143] Cap Rock,[144] and SPS[145] argue that SPS is now a 12 CP system, and they disagree with the ALJ's conclusion that SPS remains a 3 CP system. They claim that SPS' peak load ratios and other operating realities have changed substantially since the Commission last examined the SPS system in 1989. They claim that analyses by Cap Rock, SPS, and others in the proceeding take into account factors besides the availability of excess power due to the shift of Golden Spread to a partial requirements customer, such as large retail customers seeking to firm up service previously taken on an interruptible service basis and SPS' rapidly increasing growth in high load factor oil field load. They state that the evidence clearly establishes that SPS is now a 12 CP system.

69. For example, CCG states that during the hearing they introduced updated analyses of various aspects of SPS' system demand curve and other system characteristics, based on data from recent years, to show the appropriate wholesale demand cost allocator in

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¶ 61,296, at 62,132 (1989), *reh'g denied*, Opinion No. 337-A, 51 FERC ¶ 61,130 (1990) (Opinion No. 337) (same).

[138] Opinion No. 110, 14 FERC ¶ 61,075, at 61,128, *reh'g denied*, 15 FERC ¶ 61,297 (1981) (Opinion No. 110 or *Louisiana P&L*).

[139] Initial Decision at P 22.

[140] *Id.* P 24.

[141] *Id.*

[142] *Id.*

[143] CCG Brief on Exceptions at 3-23.

[144] Cap Rock Brief on Exceptions at 12-61.

[145] SPS Brief on Exceptions at 61-65.

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light of current conditions, and that, in total five witnesses concluded that SPS has now become a 12 CP system.[146] CCG argues that the Initial Decision does not discuss or dispute this evidence, undermining its ruling that a 3 CP allocator should continue to be used.[147]

70. CCG, Cap Rock, and SPS also claim that the burden of proof for a change in methodology is satisfied by a just and reasonable standard, and that the ALJ broke with precedent set in *Louisiana P&L* by ruling that "there should be a strong reason for changing allocation methodologies," and parties seeking to do so must show "major shifts in the load curve."[148] They claim that Opinion No. 110[149] states that the demand allocator should not be changed "except where there are changed circumstances or a change in policy."

3. Brief Opposing Exceptions

71. Golden Spread argues that the Initial Decision was correct in concluding that SPS' operating realities remain consistent with a 3 CP system.[150] Golden Spread submits that its demand allocation testimony demonstrates that SPS remains a 3 CP system, and that its evidence complies with the requirements set forth in *Illinois Power Co.*[151] Golden Spread asserts that Cap Rock, CCG, and SPS failed to meet the burden of proof, and shifting to a 12 CP would impose a significant cost shift on the sole entity that has done anything of significance on the system to curtail summer demand. Golden Spread claims that the ALJ recognized its comprehensive analysis and correctly concluded that "there should be a strong reason for changing allocation methodologies, given the impact on customers' expectations and the shifting price signal effects associated with a change in methodology."[152]

72. Golden Spread claims that what little change has occurred in the SPS system in metrics can be attributed to the response by Golden Spread to the 3 CP price signal.

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[146] CCG Brief on Exceptions at 4.

[147] *Id.* at 4-5, 7-11.

[148] Initial Decision at P 24.

[149] 14 FERC ¶ 61,075.

[150] Golden Spread Brief Opposing Exceptions at 17-22.

[151] *Id.* at 17 (citing *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,247-48 (1980), *aff'd in relevant part*, 15 FERC ¶ 61,050, at 61,093 (1981) (*Illinois Power*)).

[152] Initial Decision at P 24.

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Golden Spread states that it built a highly efficient generating facility that tempered the growth of the SPS summer peak, limiting cost increases to the SPS ratepayers, and providing significant energy cost savings. Golden Spread states that affirming the ALJ would ensure that customers will not be penalized for merely responding to price signals and reducing the burden they impose on a summer peaking system.

73. Golden Spread points out that the Trial Staff witness who advocated the switch to 12 CP in prefiled testimony was not as certain during the hearing, and admitted that a 12 CP would probably produce a price signal that would not discourage customers to reduce their summer load, but rather have the opposite effect.[153]

4. Commission Determination

74. We reverse the Initial Decision's finding that the 3 CP methodology remains the correct demand cost allocator for the SPS system. Although the Commission previously determined that SPS was a 3 CP system, we find that the ALJ misapplied the *Louisiana P&L* standard and overlooked numerical data in concluding that demand changes on the SPS system do not provide a "strong reason" for shifting the demand allocator to a 12 CP methodology.[154]

75. While the Commission has not established hard and fast rules for determining whether the 3 CP or 12 CP allocation method is appropriate, we have explained that the following factors should be considered when determining which allocation to use: "[t]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments."[155]

76. Historically, the Commission has considered three tests in determining whether a system is better characterized as 3 CP or 12 CP. First, the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak – the On and Off Peak test. Generally, the Commission

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[153] Tr. 2469:2-10 (Sammon).

[154] Initial Decision at P 9.

[155] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶ 61,107, at 61,230 (1978); *Illinois Power*, 11 FERC ¶ 63,040 at 65,247-48; *see also Delmarva Initial Decision*, 17 FERC ¶ 63,044 at 65,199-203 ("The Commission has not adopted any one method . . . its determination of the appropriate allocation method has rested on the facts of each case.").

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has held that a nineteen percentage point or less difference between these two figures supports using the 12 CP method.[156] The second test, the Low-to-Annual Peak test, involves the lowest monthly peak as a percentage of the annual peak. The Commission considers a range of sixty-six percent or higher as indicative of a 12 CP system.[157] The third test is the Average to Annual Peak test, and it computes the average of the twelve monthly peaks as a percentage of annual peak. Generally, the range for a utility to be considered 12 CP is eighty-one percent or higher.[158]

77. The Commission is persuaded by testimony and evidence submitted by SPS, Cap Rock, the full requirements customers,[159] and Golden Spread that substantive changes have occurred on the SPS system since the Commission last addressed the issue in 1989. The chart below is a comparison of previously accepted ratios from the peak tests indicative of a 12 CP system to the ratios submitted as evidence by various parties at trial regarding SPS' system. Differences in ratio values can be attributed to the inclusion or exclusion of interruptible loads, off-system sales, and the number of years used to calculate the average ratios shown below. The chart illustrates that applying the same analytical criterion that was primarily used in Opinion Nos. 162 and 337 to determine that SPS was a 3 CP system now clearly demonstrates it is a 12 CP utility. Even Golden Spread's witness Linxwiler's ratios, who testified in support of SPS remaining a 3 CP utility, meet the acceptable range.

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[156] *See, e.g., Illinois Power*, 11 FERC ¶ 63,040 at 65,248-49 (comparing average summer peak of ninety-four percent of annual peak to eight-month average peak of seventy-five percent of annual peak, a difference of nineteen percentage points).

[157] *Id.* (approving 12 CP where lowest monthly peak as percentage of annual peak was sixty-six percent); *Delmarva Initial Decision*, 17 FERC ¶ 63,044 at 65,201 (stating that Commission favors 12 CP method and citing 12 CP cases with low monthly peaks).

[158] *See, e.g.*, *Illinois Power*, 11 FERC ¶ 63,040 at 65,249 (approving 12 CP where average monthly peak for five-year period was eighty-one percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was eight-four percent of annual system peak); *El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶ 61,082, at 61,147 (1981) (approving 12 CP where twelve-month average was eighty-four percent of maximum peak).

[159] Central Valley Electric Cooperative, Inc., Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc.

	Lowest-To-Peak	On-Peak-Off-Peak	Average-To-Peak
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

78. In addition, in the years since Opinion Nos. 162 and 337, Golden Spread switched from a full-requirements, high summer-peaking customer on SPS' system to a partial requirements customer with a year-around, fixed contract. SPS testified that this and other factors have increasingly flattened its load profile to a point inconsistent with a 3 CP utility, as illustrated by the peak ratio percentages submitted by SPS and others.[160] We agree and will reverse the ALJ's finding that SPS is a 3 CP utility and conclude that use of the 12 CP demand allocation methodology appropriately reflects SPS' system.

C. Demand Cost Allocation Factors[161] and Post Test Year Adjustments[162]

1. Initial Decision

79. The ALJ determined that the interruptible load deductions[163] issue was resolved in the Joint Trial Stipulation, and that Cap Rock is free to further pursue the matter in

[160] *See* SPS Brief on Exceptions at 64 (citing Tr. 1560:3-9).

[161] Initial Decision at P 108-113 (Issue I.J).

[162] *Id.* P 114-119 (Issue I.K).

[163] When deriving demand cost allocation factors, interruptible loads, which are wholesale and/or retail loads whose service may be interrupted in peak periods, should be removed from the demand calculation. *See Louisiana Pub. Serv. Comm'n v. Entergy Corp*., 106 FERC ¶ 61,228 (2004) *aff'd*, 111 FERC ¶ 61,080 (2005).

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Docket No. ER06-274.[164] On the question of post test year adjustments, the ALJ determined that none should be made in the instant proceeding.[165]

2. Brief on Exception

80. In its Brief on Exceptions, Cap Rock stated that it does not except to the Initial Decision's determination on interruptible loads to the extent it is limited to the cost of service for the test year. Rather, Cap Rock asks that the Commission clarify that the stipulation does not control the treatment of interruptible loads in the analysis of the system load characteristics used in determining demand cost allocation.[166] Cap Rock asserts that the parties did not stipulate how to treat interruptible loads for purposes of analyzing the SPS system characteristics.[167] Similarly, Cap Rock does not except to the ruling that no post-test year adjustments may be made but claims it sweeps too broadly by prohibiting the use of post-test year adjustments made solely for the purpose of analyzing SPS' system load characteristics.[168] Cap Rock also requests that the Commission rule that it is appropriate to include intersystem sales in analyzing system load characteristics.[169]

3. Commission Determination

81. The Commission clarifies that the stipulation does not control the treatment of interruptible loads in the analysis of the system load characteristics in determining demand cost allocation. Cap Rock argues that retail loads that are not interruptible in the non-summer months of October through May should be included for purposes of analyzing system load characteristics.[170] Doing so has the effect of further flattening the SPS load profile, which changes its load ratio measures to be more in line with a utility with a 12 CP profile. While we make this clarification, Cap Rock's request is moot because we find that SPS is a 12 CP utility even without this adjustment. Regarding Cap

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[164] Initial Decision at P 113; *see* Exhibit J-1 at I.J.(i)-(iii) (Joint Trial Stipulation).

[165] *Id.* P 119.

[166] Cap Rock Brief on Exceptions at 62.

[167] *Id.* at 62-63.

[168] *Id.* at 59-60.

[169] *Id.* at 71.

[170] Cap Rock Brief on Exceptions at 63-69 (citing Opinion Nos. 468 and 468-A; *Delmarva Power & Light Co.*, 22 FERC ¶ 63,053, at 65,204-05, *aff'd*, Opinion No. 189, 25 FERC ¶ 61,022 (1983)).

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Rock's other two requests, we find that it would be inappropriate to include opportunity sales or inapplicable test year adjustments in the allocation of demand costs. To do so would, in effect, provide double credit to Cap Rock. If opportunity sales are included in the demand cost allocators and given revenue credit treatment, Cap Rock benefits twice through reduced demand rates and revenue credits from the proceeds of the off-system sales. Including post-test year results would have a similar effect. Accordingly, we deny Cap Rock's requests.

D. Revenue Crediting vs. Cost Allocation[171]

82. In a cost-based regime, revenues from intersystem sales are typically reflected in wholesale rates through either a revenue credit or an allocation in the cost of service. Under the revenue credit method, all the costs are allocated to requirements customers, and each requirements customer group is then subsequently credited with its share of intersystem demand revenues and energy revenues via demand and energy allocators, respectively. The revenue crediting method is most often used when sales are opportunity sales.[172] The Commission has expressed a preference for the use of revenue crediting for opportunity sales.[173] Under the cost allocation method, intersystem sales customers are treated as if they are a separate customer group in a cost of service study by including their monthly demands in the energy and demand cost allocator denominators. Thus, intersystem customers are allocated a share of the total system fixed and variable costs as if they were requirements customers. The Commission has found the allocation method appropriate for firm intersystem sales with a term of one year or more.[174]

[171] Initial Decision at P 25-33 (Issue I.B).

[172] *See Public Serv. Co. of New Mexico*, Opinion No. 146, 20 FERC ¶ 61,290, at 61,547 (1982) (Opinion No. 146) (crediting revenue from intersystem opportunity sales to native load customers).

[173] *See, e.g., Public Serv. Co. of Oklahoma*, Opinion No. 788, 57 FPC 1041, 1050 (1977) (FPC Opinion No. 788) (crediting revenue from intersystem sales to on-system customers); Opinion No. 146, 20 FERC ¶ 61,290 at 61,546-48 ("The Commission has typically used revenue crediting for opportunity sales.").

[174] *See, e.g.*, *Boston Edison Co.*, Opinion No. 53, 8 FERC ¶ 61,077, at 61,283 (1979) (finding allocation of costs to firm services preferable to revenue credit approach).

1. Initial Decision

83. In the Initial Decision, the ALJ found that the nine SPS intersystem market-based sales at issue,[175] excluding the expired sales to Manitoba Hydro and Midwest Energy, are more in line with what the Commission found to be "opportunity sales" in *Florida Power & Light Co.*[176] and *Kentucky Utilities Company*,[177] rather than the type of requirements sales for which SPS is required to plan, construct, and maintain capacity.[178] The ALJ also found that the sales at issue are fundamentally different from long-term sales to SPS' cost of service customers and have a lesser status than the native load. Therefore, the ALJ determined that the revenues from these sales should be credited against the cost of serving the requirements customers whose rates are at issue in this proceeding.

2. Briefs on Exceptions

84. Trial Staff and SPS except to the ALJ's determination to use the revenue crediting methodology. SPS states that, consistent with *Florida P&L*, revenue credit treatment has been limited to short-term sales of less than a year, usually referred to as opportunity sales, where no system planning is involved to ensure that a firm capacity sale commitment can be met over the term of the underlying contract. Trial Staff and SPS argue that the sales in question are all long-term firm sales that are part of the "system" for which it must plan, construct, maintain, and operate its system of transmission, generation, and power resources,[179] and claim that the allocation methodology is more appropriate.

85. Trial Staff and SPS cite Order No. 2001 for the proposition that the market-based sales at issue are long-term sales.[180] They conclude that these sales should thus be treated like requirements sales for cost-of-service purposes.[181]

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[175] Ex. CCG-1 at 36.

[176] 33 FERC ¶ 61,116, at 61,247 (1985) (*Florida P&L*).

[177] 15 FERC ¶ 61,002 (1981).

[178] In these cases the Commission determined that in developing rates, fixed costs should not be allocated to services that do not cause the utility to plan, construct, or maintain capacity.

[179] Trial Staff Brief on Exceptions at 9-12; SPS Brief on Exceptions at 58-61.

[180] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, at 30,171 (2002) (defining long-term market-based rate sale as equal to or greater than one year).

86. Trial Staff and SPS also contend that the sales in question are "firm loads" according to the Commission's analysis in Opinion No. 468,[182] and thus are not "fundamentally different" from the services rendered to SPS' cost-of-service customers.[183] Trial Staff and SPS state that SPS' generation resource planning is not done for individual customer load, but rather uses the total company firm energy and peak demand to determine the best overall generation mix to serve all customers. Furthermore, SPS states that it has no ability to refuse or curtail service to either group of firm service customers except in the case of *force majeure* or a system emergency.

87. CCG generally agrees with the ALJ's revenue crediting determination, and excepts only to the ALJ's ruling that the sales contracts to Manitoba Hydro and Midwest Energy should not be treated as revenue credits merely because the contracts expired during the 2004 test year period.[184] CCG claims that the expiration of the contracts in 2004 simply means that they should be treated as short-term and non-firm sales, which are revenue-credited.

3. Briefs Opposing Exceptions

88. CCG states that only its witness performed a substantive review of the specific terms and conditions of the contracts in question, and that Trial Staff relied upon SPS' incomplete and inaccurate analysis of the contracts to determine that the sales in question are not different from true requirements contracts. CCG states that its witness' analysis clearly reveals that the sales in question are substantially different from requirements contracts in that they are voluntary, market-based sales of limited duration, and only available for as long as SPS could claim that it had surplus capacity, which qualifies them as opportunity sales.[185] Furthermore, CCG claims that the contracts make clear that interruption will occur before SPS' own ultimate customers and, in contrast to true firm

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[181] Trial Staff Brief on Exceptions at 9-12; SPS Brief on Exceptions at 58-61.

[182] *Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 106 FERC ¶ 61,228, at P 74-75 (2004), *affirmed*, Opinion No. 468-A, 111 FERC ¶ 61,080 (2005) (When a utility makes a commitment to serve a firm load, it commits to serve that load at all times (absent a *force majeure* event on the system)).

[183] Initial Decision at P 33.

[184] Tr. 2088:21-2089:14 (Heintz).

[185] CCG Brief Opposing Exception at 53.

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loads, relieve SPS of the requirement to deliver and the customer of the obligation to pay in the event of adverse conditions.[186]

89. CCG and PNM argue that SPS' reliance on *Wisconsin* is unfounded, and the sales must be considered opportunity sales because SPS does not "plan, construct, or maintain" the capacity in the long-run. CCG claims SPS admits that because its wholesale and retail native load requirements are growing, its marketing of opportunity sales from its generation will shrink, a core characteristic of opportunity sales as determined in *Florida P&L* and *Kentucky Utilities Co.*[187] Furthermore, CCG states the fact that SPS has had to buy short-term capacity from third parties when its own resources were insufficient demonstrates that it has not incurred long-term fixed costs to build capacity specifically to serve the 2004 market-based opportunity sales.

90. CCG states that opportunity sales are made to market temporary surplus of capacity and/or energy, and the length of a contract does not exclude it from being considered an opportunity sale. CCG states that even though the sale was for 13 years in *Public Service Co. of New Mexico*,[188] the Commission determined that it was clearly an opportunity transaction because it was undertaken to utilize idle capacity. CCG also argues that in *Tampa Elec. Co.*, the Commission found revenue crediting the cost-of-service for the underlying requirements customers to be appropriate for a 4-year and an 18-year contract to an intersystem customer.[189]

91. CCG states that the Commission has long held that opportunity sales should be revenue credited. CCG also states that Opinion No. 337 found "all of the revenues from off-system sales should be credited to the on-system customers."[190]

92. SPS supports the ALJ's conclusion to exclude the Manitoba Hydro and Midwest Energy sales from the test year for the cost of service study on the basis that neither sale was extended or replaced in 2005.[191]

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[186] *Id*. at 52-53.

[187] *Id.* at 56 (citing *Florida P&L*, 33 FERC ¶ 61,116, and *Kentucky Utils. Co.*, 15 FERC ¶ 61,002, at 61,005 (1981)).

[188] *Public Serv. Co. of New Mexico*, 43 FERC ¶ 61,469 (1988).

[189] *Tampa Elec. Co.*, 71 FERC ¶ 61,245 (1995), *aff'd*, 83 FERC ¶ 61,262 (1998).

[190] Opinion No. 337, 49 FERC ¶ 61,296 at 62,133.

[191] SPS Brief Opposing Exceptions at 34-35.

4. Commission Determination

93. We will affirm the ALJ's determination that revenue crediting is the proper cost of service treatment for the sales at issue. This conclusion is consistent with our finding made earlier, that SPS' market-based intersystem sales are opportunity sales. The sales were entered into when SPS experienced a temporary level of excess capacity when Golden Spread changed from a full to partial requirements customer in 2000. While these sales were for firm power and some were for more than one year, SPS neither planned, constructed, or maintained its system to accommodate these sales, a general predicate to classify the sales as other than opportunity sales. And, as demonstrated by CCG, SPS' opportunity sales, while not interruptible, do get interrupted prior to the wholesale requirements customers.[192] The fact that some of the sales could be considered long-term under the Commission's market-based rate policy is not a determining factor because, as noted above, the Commission has considered sales of up to thirteen years as opportunity sales. The Commission has expressed a preference for the use of revenue crediting for opportunity sales.[193] Accordingly, we direct that SPS revenue credit these sales.

94. However, the Commission disagrees with the ALJ's exclusion of the expired sales contracts to Manitoba Hydro and Midwest Energy from revenue credit treatment. The ALJ excluded these contracts because "they have expired and whether similar sales will recur is speculative."[194]

95. The test year in this proceeding is calendar year 2004. SPS states that two "long-term firm power sales agreements that expired in 2004 . . . will not be in effect on or after January 1, 2005, when any rate changes made in this case would be made effective."[195]

Specifically, a 100 MW sale to Manitoba Hydro Energy Board (Manitoba Hydro) terminated December 31, 2004, and a 25 MW sale to MidWest Energy, Inc. (Midwest Energy) terminated May 31, 2004.[196]

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[192] CCG Brief Opposing Exceptions at 52-53.

[193] *See, e.g.*, Opinion No. 788, 57 FPC at 1050 (crediting revenue from intersystem sales to on-system customers); Opinion No. 146, 20 FERC ¶ 61,290 at 61,546-48 ("The Commission has typically used revenue crediting for opportunity sales.").

[194] Initial Decision at P 33.

[195] Ex. SPS-37 at 11:11-16.

[196] *Id.*

96. Although the contracts expired during the test year, these revenues should not be excluded simply because they expired during the test period. As the name "test period" implies, the test period costs and revenues form the basis for testing the justness and reasonableness of a rate.[197] The development of that rate involves (1) total utility expenses *for the test period*, (2) allocation of a portion of those expenses to wholesale service based upon wholesale cost responsibility *during the test period*, and (3) development of a unit charge or rate that is based upon wholesale billing determinants projected *for the test period.*[198] By synchronizing these three parameters - expenses, allocation factors, and billing determinants - the resulting unit rate should allow the utility to fully recover its cost of providing wholesale electric service. While historic test period data may be adjusted to reflect known and measurable changes that affect revenues and costs,[199] such adjustments must also be synchronized so that the resulting unit charge would not result in over- or under-recovery of the utility's cost of providing wholesale electric service.

97. Here, the fact that the two contracts expired and were not replaced with new contracts is not enough to justify elimination of the revenue credits associated with these contracts. Instead, other related factors would need to be considered, such as whether SPS reduced its production resources after the termination of its obligation to supply Manitoba Hydro and Midwest Energy, or whether, instead, the capacity previously used to supply those contracts was subsequently used to meet load growth of SPS' retail and wholesale requirements customers. Elimination of the revenue credits associated with these contracts without reflecting other related changes in expenses, allocation factors, and billing determinants, would violate the principle that these parameters must be synchronized so that the resulting rate would not result in over- or under-recovery of the utility's cost of providing wholesale electric service.

E. Cash Working Capital Allowance[200]

98. A cash working capital allowance (CWCA) is an amount included in rate base to allow a company to pay "out-of-pocket" expenses that are incurred in daily operations before the expenses are recovered through customer revenues. The Commission has used two methods to calculate CWCA, the 45-day rule, and a fully developed and reliable

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[197] *See Delmarva Power and Light Co.*, Opinion No. 262, 38 FERC ¶ 61,098, at 61,257 (1987).

[198] *Id.*

[199] *See, e.g.*, 18 C.F.R. §§ 35.13(a)(2)(D) and 35.13(d)(1)(ii) (2007).

[200] Initial Decision at P 44-52 (Issue I.D).

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lead-lag study. The Commission has stated that the 45-day rule has "produced reasonable results over the years without the expense of prolonged litigation . . . [and] it affords substantial advantages from the standpoints of administrative convenience."[201] The Commission has also found that the 45-day rule avoids imposing the costs of a detailed lead-lag study on utilities, and ultimately, on their consumers.[202] The Commission also allows parties to submit fully developed and reliable lead-lag studies to develop a working capital allowance in lieu of the 45-day rule.

99. A fully developed and reliable lead-lag study's revenue lag calculation must be based on, or confirmed by, a study of the wholesale customers' actual bill paying practices. Absent this, the lead-lag study cannot be found to reflect the actual cash needs of the company.[203] However, where a study is conducted based on assumptions that payments were received on time, rather than on actual bill paying practices, and those assumptions are verified by checking the data against actual payment practices, the Commission affords the lead-lag study the same credibility as if it had been based on data derived from payments.[204]

1. Initial Decision

100. In the Initial Decision, the ALJ determined that the 45-day rule should be applied to determine SPS' CWCA.[205] The ALJ found that CCG's lead-lag study is not fully developed and reliable, stating that CCG could not provide an explanation of the sampling methodology for the lead-lag study, and that the study is based on too many assumptions that were not necessary and created the possibility of repetition error.[206]

2. Brief on Exception

101. CCG argues that the ALJ erred in ruling that a 45-day CWCA is appropriate.[207] CCG argues that the ALJ incorrectly rejected the lead-lag study merely because it was

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[201] *Carolina Power and Light Co.*, 6 FERC ¶ 61,154, at 61,295 (1979).

[202] *Id.*

[203] *Pennsylvania Power Co.*, 12 FERC ¶ 61,049, at 61,080 (1980), *aff'd, Boroughs of Ellwood City v. FERC,* 731 F.2d 959 (1984).

[204] *Cities of Aitken*, 704 F.2d 1254 (D.C. Cir. 1982).

[205] Initial Decision at P 53.

[206] *Id.* P 53-55.

[207] CCG Brief on Exceptions at 16-24.

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not based on 100 percent actual data. CCG claims that the study relied on limited assumptions, and the assumptions used were advantageous to SPS and disadvantageous to CCG, the proponent of the assumptions. CCG further states that the Commission has determined that such a study may establish a utility's working capital requirements, even if the study is not based on 100 percent of actual service and payment data, if the opponent of the study fails to present persuasive evidence that the study was not reasonably illustrative of the utility's cash requirement.[208]

102. CCG claims that the ALJ applied an overly-stringent test for the "fully developed and reliable" standard. It asserts that the Commission requires lead-lag studies to be prepared only so that "the Commission can be *reasonably confident* that the study reflects the actual, rather than just an approximation of, the cash needs of the utility."[209] CCG further argues that the Commission is particularly flexible in determining what is fully developed and reliable when the study is reliable to show a negative allowance.[210] CCG claims its study produces a three to four day negative lag, and therefore it is reasonable to adopt a zero cash working capital allowance.

3. Briefs Opposing Exceptions

103. Trial Staff and SPS claim that none of CCG's three attempted lead-lag studies was fully developed because CCG used the contract terms to determine cash flow and made no attempt to determine the actual billing and payments of revenues and expenses.[211] SPS asserts that the information needed to determine the actual service periods was readily available, and CCG's witness did not follow through on plans to obtain it.[212] Trial Staff further states that CCG's data were indeed questioned, and CCG's claim that no party presented evidence showing substantive error is irrelevant because the study itself was insufficient.[213]

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[208] *Id.* at 21 (citing *Central Illinois Pub. Serv. Co.*, 8 FERC ¶ 63,022 (1979), *aff'd in relevant part*, 10 FERC ¶ 61,162 (1980) (*Central Illinois*)).

[209] *Pennsylvania Power Co.*, 12 FERC ¶ 61,049, at 61,080 (1980), *aff'd, Boroughs of Ellwood City v. FERC*, 731 F.2d 959 (1984) (emphasis added).

[210] *Minnesota Power and Light Co.*, 16 FERC ¶ 63,012, at 65,060 (1981).

[211] Trial Staff Brief Opposing Exceptions at 34; SPS Brief Opposing Exceptions at 19.

[212] SPS Brief Opposing Exception at 21.

[213] Trail Staff Brief Opposing Exception at 34.

4. Commission Determination

104. We affirm the ALJ's ruling and agree with Trial Staff and SPS that CCG's lead-lag study was not fully developed and reliable. For example, the record shows that the actual invoices were never inspected.[214] Thus, the assumptions made with regard to the service periods and payment dates were never validated against actual payment practices.[215] Therefore, we cannot be reasonably confident that the study reflects the actual rather than a mere approximation of the cash needs of the utility. Accordingly, we affirm the ALJ's ruling that the 45-day rule is appropriate and consistent with Commission policy to determine SPS' CWCA.

F. Renewable Energy Credits[216]

105. Renewable Energy Credits/Certificates (RECs) are required pursuant to some state programs intended to promote renewable energy. In furtherance of that goal, these credits may be used to offset the cost of purchasing renewable energy. The issue in this case is whether SPS should reduce, by the amount of the credit, the cost that it flows through the FCAC.

1. Initial Decision

106. In the Initial Decision, the ALJ determined that even though the Commission's regulations do not contemplate the inclusion of renewable energy credits proceeds in the FCAC, the sales of renewable energy credits should not be separated from the costs of wind energy purchases. The ALJ explained that not requiring the wind energy purchase price to be offset by the renewable energy credits overstates the cost of these purchases and could provide a windfall to SPS.[217]

2. Briefs on Exceptions

107. Trial Staff argues that the ALJ's determination that the renewable energy credits should be flowed through the FCAC should be reversed because the Commission's regulations do not allow FCAC treatment of renewable energy credits.[218]

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[214] Initial Decision at P 54 (citing Tr. 817-19 (Humphrey).

[215] *Id.* P 56.

[216] *Id.* P 73-79 (Issue I.H).

[217] *Id.* P 79.

[218] Trial Staff Brief on Exceptions at 13-14.

108. SPS excepts on the same grounds as Trial Staff and adds that the requirement to flow its renewable energy credits through its FCAC would violate the Administrative Procedure Act.[219] SPS also argues that the Commission's findings in *Cincinnati Gas & Electric Co.*,[220] where the Commission permitted the inclusion of emission allowances in the FCAC even though the Commission's regulation did not explicitly reference inclusion of such costs, does not apply here. SPS points out that the recovery of the cost of emission allowances related to power purchases was consistent with the Commission's FCAC policy, whereas the recovery of renewable energy credits is not.[221]

3. Briefs Opposing Exceptions

109. CCG argues that SPS' current revenue crediting approach for renewable energy credits would result in a significant mismatch of costs. By design, if SPS chose to avoid or defer selling renewable energy credits in a ratemaking test year, it would then reap all of the profits for sales of renewable energy credits in subsequent years. CCG adds that this problem will become magnified in future years as SPS increases its purchases from wind generation. By allowing FCAC treatment, the actual cost-recovering nature of the FCAC will be maintained, according to CCG.

110. PNM argues that the ALJ's decision is entirely consistent with the Commission's ruling in *Cincinnati Gas & Electric*. PNM concludes that the ALJ correctly ruled that offsetting the proceeds of REC sales is necessary to determine the true "total cost" of SPS' wind energy purchases for purposes of FCAC recovery.

4. Commission Determination

111. We affirm the ALJ's conclusion that not addressing the issue of renewable energy credits in the FCAC would result in overstating the total cost of wind purchases. While the Commission's regulations do not directly address FCAC treatment of renewable energy credits, the Commission's regulations do provide that the total cost of purchased economic energy must be flowed through the FCAC.[222] Therefore, when SPS sells

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[219] SPS Brief on Exceptions at 78.

[220] 71 FERC ¶ 61,083, at 61,294 (1995) (*Cincinnati Gas & Elec.*).

[221] *Id.* at n.80.

[222] Under the Commission's FCAC regulations, the "[*t*]*otal cost of the purchase* is all charges incurred in buying economic power and having such power delivered to the buyer's system. The total cost includes, but is not limited to, capacity or reservation charges, energy charges, adders, and any transmission or wheeling charges associated with the purchase." 18 C.F.R. § 35.14(a)(11)(i) (2007); *see* 18 C.F.R. § 35.14(a)(2)(iii)

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renewable energy credits, it must subtract the proceeds of these sales from the cost of the wind energy purchases it flows through the FCAC. Otherwise, SPS would not be including in the FCAC the true total cost of the purchase of wind power.

112. In addition, we find that our determinations in *Cincinnati Gas & Electric* are applicable to the instant proceeding. The Commission's logic in requiring FCAC treatment of emission allowances, which increase the purchase cost and "constitute[] a component of the purchased power costs that are eligible for fuel adjustment clause recovery, just as other non-fuel components of purchased power costs," applies equally to renewable energy credits that decrease the purchase cost.

G. Pollution Control Construction Work in Progress[223]

113. Pollution control construction work in progress (pollution control CWIP or CWIP) refers to any expenditure of a utility in the process of constructing a pollution control facility.[224] A pollution control facility is an identifiable structure or portions of a structure that is designed to reduce the amount of pollution produced by the utility.[225] In determining if a facility qualifies as a pollution facility, the Commission considers, among other things, "evidence showing that such facilities are for pollution control."[226] Commission regulations permit a public utility to include costs of pollution control CWIP from qualifying pollution control facilities in its rate base.[227]

1. Initial Decision

114. The ALJ determined that a pollution control CWIP of $3,835,043 is properly included in SPS' rate base. The ALJ stated that the Commission's regulations permit the recovery of pollution control CWIP. Furthermore, the ALJ states that SPS submitted a

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(2007) (providing that fuel and purchased economic power costs shall be the cost of "[t]he total cost of the purchase of economic power, as defined in paragraph (a)(11) . . . .").

[223] Initial Decision at P 57-61 (Issue I.E).

[224] 18 C.F.R. § 35.25 (2007).

[225] *Id.* § 35.25 (b)(4).

[226] *Id.* § 35.25(c)(1)(c).

[227] *Id.* § 35.25 (c)(1).

list of pollution control facilities[228] it includes in its rate base as well as testimony indicating they are pollution control facilities associated with existing facilities SPS owns.[229]

2. Brief on Exception

115. CCG asserts that SPS has not met the requirements in 18 C.F.R. § 35.25 to include pollution control CWIP, and therefore the ALJ's determination is an exception to the rate-making principle that customers cannot be required to pay for facilities that are not used and useful during the applicable test year.[230] CCG argues that SPS made no showing that its claimed pollution control facilities are "[an] identifiable structure or portions of a structure that is designed to reduce the amount of pollution produced by the power plant"[231] as required by the Commission's regulations. CCG states that the Commission has historically rejected CWIP when a utility does not describe the facility allegedly serving a pollution control function in sufficient detail for the Commission to make a determination.[232]

116. CCG also claims SPS did not comply with the requirement to use forward-looking allocation ratios to allocate its requested total system CWIP to its customers,[233] which it states is a precondition for the inclusion of pollution control CWIP in the rate base.[234] CCG states that SPS employed a single demand allocation ratio derived from 2004 test year data for all production-related costs, including CWIP projects.[235] CCG cites Order No. 474 in asserting that this will result in an unjust "double whammy"[236] effect on a

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[228] Exhibit SPS-52.

[229] Initial Decision at P 61 (citing Tr. 2225 (Blair)).

[230] CCG Brief on Exception at 24-30.

[231] 18 C.F.R. § 35.25(b)(4).

[232] In support of its position, CCG cites *Southern California Edison Co.*, 38 FERC ¶ 61,040, at 61,109 (1987) and Opinion No. 110, 14 FERC ¶ 61,075 at 61,117.

[233] 18 C.F.R. § 35.25(c)(4) (2007).

[234] CCG cites, *inter alia*, *Maine Yankee Atomic Power Co.*, 66 FERC ¶ 61,375, at 62,252 n.7 (1994) and *South Carolina Elec. & Gas Co.*, 63 FERC ¶ 61,218, at 62,599-600 (1993) (*South Carolina*).

[235] Tr. 2194:4-15 (Heintz).

[236] *Electric Rates; Construction Work in Progress; Anticompetitive Implication*, Order No. 474, 52 Fed. Reg. 23,948 (June 26, 1987), FERC Stats. & Regs. ¶ 30,751, at

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utility's wholesale customer by requiring that customer to pay for the costs of the utility's future facilities even though the customer may have purchased or incurred the costs to construct alternate capacity.

117. CCG claims that SPS failed to comply with section 35.25(f) of the Commission's regulations, which requires a utility to propose accounting procedures that ensure that wholesale customers will not be charged for (1) both capitalized allowance for funds used during construction (AFUDC) and corresponding amounts of CWIP proposed to be included in the rate base, and (2) any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities.

3. Briefs Opposing Exception

118. Trial Staff and SPS argue that the CWIP regulations that CCG claims the ALJ did not address apply only when a utility is seeking to initiate or change its CWIP in a section 205 rate case, and not in a section 206 complaint case.[237] Furthermore, SPS claims it has met the requirements to include pollution control CWIP in its rate even though the requirements are not applicable in this case. Trial Staff and SPS claim that SPS has provided adequate evidence that the facilities it has included are in fact pollution control facilities. SPS also states it provided assurances that SPS would not charge customers for both AFUDC and pollution control CWIP in rate base, explaining how SPS would track CWIP recovery in wholesale rates to assure that in future years there would be no AFUDC accruals recovered in a plant on this same CWIP. SPS provided an example of how the accounting would track the CWIP to ensure that customers would not be charged for the same projects both in CWIP and AFUDC.[238]

4. Commission Determination

119. The Commission affirms the ALJ's finding that pollution control CWIP is properly included in SPS' rate base, as it is allowable by the Commission's regulations.[239] Section 35.25(c)(1)(i) of the Commission's regulations states that "[a]ny CWIP for pollution control facilities allocable to electric power sales for resale may be

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30,702 n.5 (1987) (defining "double whammy"). CCG also cites *South Carolina*, 63 FERC ¶ 61,218, at 62,599.

[237] 18 C.F.R. § 35.25(c)(4); 18 C.F.R. § 36.26(c) (2007).

[238] Exhibits SPS-158 and SPS-159.

[239] 18 C.F.R. § 35.25(c) (2007).

included in the rate base of the public utility." SPS provided evidence and testimony indicating the facilities are properly designated as pollution control facilities. For example, Exhibit SPS-52 provides work order numbers, descriptions, and the costs for facilities and equipment that SPS included in its rate base as pollution control CWIP. SPS also submitted in Exhibits SPS-158 and 159 a description of the accounting procedures it will undertake to ensure that wholesale customers will not be charged for both AFUDC and CWIP in future years. We are persuaded by SPS' evidence that SPS will not charge customers for both pollution control CWIP and AFUDC in rate base. CCG has not provided any evidence to convince us otherwise. Accordingly, we find that SPS' pollution control CWIP is properly allowable in its rate base.

H. Undistributed Subsidiary Earnings[240]

120. Income earned by a utility's subsidiary appears in the utility's Account 216.1, Undistributed Subsidiary Earnings. These funds are only represented on paper, and not actually available for the utility to use. Once the subsidiary pays a dividend or the utility sells the subsidiary, the amount becomes available for the utility to use at its discretion. The funds from the dividend or sale are then characterized as distributed subsidiary earnings, and the amount is moved to Account 216.0, Retained Earnings. In 1997, SPS sold two subsidiaries, Utility Engineering Corp. and Quixx Corp. and recorded the proceeds as undistributed subsidiary earnings.[241]

1. Initial Decision

121. The ALJ states that although the operations of the subsidiaries at issue did not involve the provision of utility service, the $22,855,828 from the sale of the subsidiaries was properly moved to account 216.0 (Retained Earnings) in 2004.[242] Thus, the ALJ ruled that the funds are no longer undistributed subsidiary earnings, but rather retained earnings available for use by SPS to invest in its electric operations. Therefore the ALJ held that the funds are includable in SPS' equity balance under *United Gas Pipe Line*.[243]

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[240] Initial Decision at P 62-69 (Issue I.F).

[241] *Id.* P 64.

[242] Tr. 2197 (Heintz).

[243] 13 FERC ¶ 61,044, at 61,096 (1980) (stating that distributed subsidiary earnings (retained earnings) are available to the utility for rate base investment (or retirement of debts previously used for rate base investment) and are therefore properly includable in capitalization) (*United Gas Pipe Line*).

2. Brief on Exceptions

122. CCG argues that it was erroneous for the ALJ now to allow SPS to treat the earnings as retained earnings (Account 216.0) after SPS inexplicably treated the earnings as undistributed subsidiary earnings (Account 216.1) for seven years after the sale of the subsidiaries.[244] Furthermore, CCG argues that, even assuming the shift from Account 216.1 to Account 216.0 was proper for accounting purposes, SPS has not shown that including the earnings in SPS' common equity is proper for ratemaking purposes.[245] CCG claims that the undistributed subsidiary earnings should be removed from SPS' common equity calculation because the subsidiaries are not affiliated with the electric operation of SPS, and wholesale ratepayers should not be required to pay a return on earnings derived from non-existent, non-utility operations.[246]

3. Brief Opposing Exceptions

123. SPS argues that CCG has inaccurately characterized the funds as undistributed subsidiary earnings, because the funds had been distributed to SPS' retained earnings account by the end of 2004 and were, thereafter, available for investment in utility rate base and no longer represented undistributed subsidiary earnings.[247] SPS claims that all retained earnings represent a return from an investment and the fact that some of SPS' retained earnings may have had their source in SPS' investment in a subsidiary is beside the point. SPS argues that by using straightforward accounting logic, it is clear the funds are available for investment in SPS' regulated utility business, and are therefore properly recognized in the test year capital structure used for rate regulation.[248]

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[244] CCG Brief on Exceptions at 31.

[245] *Id.* at 31-32 (citing letter dated March 22, 2006, from Ms. J. G. Nicholas, Chief Accountant and Director, Division of Audits and Accounting, in *Delta Energy Center, LLC*, Docket No. AC06-10-000 ("Our determination that Delta's lease is a capital lease is for accounting purposes only and does not constitute approval of the appropriate level or timing of cost recovery for ratemaking purposes. Your accounting for the lease costs should be adjusted, if appropriate, to reflect the ratemaking treatment approved by the Commission.")).

[246] CCG Brief on Exceptions at 30-31.

[247] SPS Brief Opposing Exceptions at 13.

[248] *Id.* at 13-14.

4. Commission Determination

124. We affirm the ALJ's ruling that the funds are retained earnings, not undistributed subsidiary earnings as CCG claims, and therefore includable for ratemaking purposes. In *United Gas Pipe Line*, the Commission determined that because undistributed subsidiary earnings are not available for purposes of rate base investment, they must be excluded from capitalization. Here, the funds are no longer in the control of SPS' former subsidiaries and are available for investment in SPS' regulated utility business. The fact that the amount from the sale of the subsidiaries was treated as undistributed subsidiary earnings for seven years after the sale of the subsidiaries is not relevant. SPS explained that there was a note payable over a five year term to SPS, and the note was held on the books until the note was paid.[249] While the amounts could have been transferred to Account 216.0, Retained Earnings, SPS stated that they were transferred in 2004, and therefore are now properly retained earnings includable in SPS' rate structure.

125. We also agree with SPS that the source of the retained earnings is not relevant. CCG claims that although the funds may now properly be retained earnings for accounting purposes, they may not be properly included for ratemaking purposes because the funds represent a return from an investment in a subsidiary. The Commission disagrees. Retained earnings represent a return from investment, or net profit after dividends are paid, and are a component of a firm's capitalization.[250] As stated above, the funds are properly included in the Retained Earnings Account and, therefore, are includable for ratemaking purposes.

I. Allocation of Demand Side Management Programs[251]

126. Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. The issue here is whether SPS should be permitted to include the cost of demand side management programs in its cost of service for wholesale customers.

1. Initial Decision

127. In the Initial Decision, the ALJ determined that the costs of demand side management programs are properly allocated to wholesale customers. The ALJ

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[249] Initial Decision at P 68 (citing Tr. 2198 (Blair)).

[250] SPS Brief Opposing Exceptions at 14.

[251] *See* Initial Decision at P 70-72 (Issue I.G).

determined that SPS had provided sufficient evidence that its demand side management programs had reduced its peak generation and thereby benefited customers by reducing the cost of providing service.[252]

2. Brief on Exception

128. Trial Staff asserts that SPS did not provide enough hard data to support a finding that its wholesale customers benefited from the demand side management programs. Trial Staff argues that SPS must perform a study that demonstrates conclusively that the demand side management programs have allowed SPS to reduce load on its system to the point where SPS has been able to delay the installation of new generation capacity.[253]

3. Brief Opposing Exception

129. SPS contends that Trial Staff's assertion that SPS did not prove the benefits of its demand side management programs is incorrect. SPS states that in the past four years demand side management programs have reduced energy needs by approximately 323,000 MWh and shaved SPS' system peak generation needs by approximately 38 MW.[254] SPS argues that while it cannot claim that the demand side management programs have yet enabled it to avoid expenditures on building new generation capacity, Trial Staff has not justified a requirement that demand side management programs must delay generation capacity additions in order for their costs to be included in rate base.[255]

4. Commission Determination

130. We find sufficient justification for allocating the costs of demand side management programs to wholesale customers, because SPS has demonstrated that its demand side management programs have benefited wholesale customers by reducing energy needs by approximately 323,000 MWh and shaving SPS' system peak generation needs by approximately 38 MW.[256] We disagree with Trial Staff that there must be a conclusive demonstration that the programs have specifically delayed the installation of new generation capacity. Such a requirement is an unduly stringent standard for cost

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[252] Initial Decision at P 72.

[253] Trial Staff Brief on Exceptions at 12-13.

[254] SPS Brief Opposing Exceptions at 15 (describing capacity reduction due to DSM programs).

[255] SPS Brief Opposing Exceptions at 14-15.

[256] *See* Exhibit SPS-89.

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recovery (i.e., deferral of new generation capacity additions) and may discourage companies from considering all cost-effective options in meeting customer needs, including generation, transmission and demand resources. While we agree that there must be evidence of a program's benefits, we are satisfied that, in the instant case, SPS' evidence is sufficient.[257]

IV. Issues Relating to SPS' Prior FCAC

131. The FCAC issues in this case fall into two categories, those concerning the SPS FCAC that was in effect prior to the effective date of the proposed FCAC (January 1, 2005) and those concerning the FCAC that SPS proposed in the FPA section 205 filing that is involved in the instant case.[258] Due to a settlement between SPS and its customers, disputes arising from the former FCAC are governed by Order No. 517, which was issued in 1974 by this agency's predecessor, the FPC.[259] In contrast, issues arising from the proposed FCAC are governed by this Commission's Order No. 352, issued in 1983.[260]

A. Long-Term Energy-Related Qualifying Facility (QF) Costs[261]

132. FPC Order No. 517 permitted utilities to flow through the FCAC "the net energy cost of energy purchases, exclusive of capacity or demand charges . . . when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy . . . ."[262] In 1990, SPS amended its contracts to include a fuel clause that permitted purchases from QFs at or below SPS' avoided variable energy cost to be

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[257] In the Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1261 *et seq.*, 119 Stat. 594 (2005), Congress stated that "[i]t is the policy of the United States that time-based pricing and other forms of demand response . . . shall be encouraged."

[258] *See Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (accepting and suspending proposed FCAC).

[259] FPC Order No. 517, 52 FPC at 1308.

[260] *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*, FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

[261] Initial Decision at P 126-131 (Issue II.A.2).

[262] FPC Order No. 517 (amending section 35.14(a)(2)(c) of the Commission's regulations).

included in the customer's FCAC. As drafted, this FCAC varied slightly from the Commission's regulations because it permitted SPS to flow through costs other than "net energy costs."

1. Initial Decision

133. The ALJ concluded that the record supports a finding that SPS was permitted, as a result of the settlement in Docket No. ER89-50-000 and subsequent agreements with its wholesale customers, to collect energy-related costs of its QF purchases at or below its avoided variable energy costs, as determined by state regulatory authorities.[263] The ALJ found that the "plain language" of the settlement permits the collection of the energy-related costs of SPS' QF purchases at or below avoided variable energy costs. The ALJ also found that the customers did nothing to complain about the inclusion of these costs in the FCAC calculations that they routinely received and reviewed.

2. Briefs on Exceptions

134. Trial Staff argues that the ALJ erred in concluding that SPS was permitted to collect through its former FCAC all energy-related costs of its QF purchases at or below its avoided variable energy costs, and that the ALJ should have found that only the net energy costs of a QF purchase made on an economic dispatch basis may be passed through.[264]

135. Trial Staff also argues that the ALJ's conclusion is correct only if the language of the settlement is considered outside of the context in which the settlement was agreed upon. However, Trial Staff points out that in 1990, when the settlement added the QF provision to the SPS FCAC, the only QF purchases SPS was making were puts.[265] Trial Staff also states that SPS did not have any QF contracts for capacity. [266]

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[263] *Id.* P 130-31.

[264] Trial Staff Brief on Exceptions at 14-18.

[265] In a put, a QF would have the right to require SPS to make a purchase under the relevant regulations.

[266] Trial Staff argues that the record shows capacity QF purchases are of more recent origin. Trial Staff Brief On Exceptions at 15. Trial Staff states that the QF contract SPS has with Borger Energy Associates, L.P. was dated May 23, 1997, and its QF contract with Sid Richardson Carbon, Ltd. was dated August 1, 2001. *Id.* at 16-17; *see also* Exhibit CCG-46 at 37-38 (Testimony of Daniel). The QF contract SPS had with Engineered Carbons, Inc. went into effect in 1989, but was modified on August 15, 1999,

(continued…)

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136. Trial Staff further argues that the Commission should reject SPS' recovery through its former FCAC of energy-related costs incurred under long term QF contracts. Trial Staff argues that SPS should be required to refund monies that were improperly included in the fuel clause and that "the Commission's policy of strictly construing its FCAC regulations should be followed."[267]

137. CCG argues that the "plain language" of the settlement in Docket No. EL89-50[268] cannot be reasonably read to contemplate reliability purchases from QFs, because these transactions did not exist at the time the settlement was executed.[269] Thus, CCG states, the Commission should interpret the settlement in the context of the relevant evidence of the situation and relations of the parties. CCG adds that it is unlikely that the Commission would have sanctioned such a radical departure from the regulations established in FPC Order No. 517[270] if the Commission believed that one or both of the parties intended "purchases" to be so broad as to include the non-fuel energy components of long-term reliability purchases.

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to provide for capacity payments and increased energy purchases if the plant was expanded to produce more than twelve MW net output. *Id*.

[267] Trial Staff Brief on Exceptions at 18.

[268] The relevant section of SPS' former FCAC reads:

> 2. Fuel costs (F) shall be the cost of:
>
> (i) Fossil and nuclear fuel consumed in Company's own plants, and Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.
>
> (ii) Plus, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. *Included therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.*

(Emphasis added by CCG).

[269] CCG Brief on Exceptions at 39-43.

[270] 52 FPC at 1308.

3. Brief Opposing Exceptions

138. SPS argues that nothing in the language of the prior agreements or the SPS FCAC limits recovery to "QF puts" or fuel costs associated with long-term transactions.[271] According to SPS, the agreements are unambiguous and attribute no significance to whether the purchases are associated with the purchase of firm capacity or whether they are simply energy purchases that are made at an avoided cost rate. SPS adds that although at the time the settlement agreements were negotiated SPS had no avoided capacity costs, the Commission's QF regulations then in effect clearly contemplated the obligation of electric utilities to enter into long-term agreements for the purchase of QF capacity and associated energy, which is what SPS did several years later.

139. SPS also argues that the intervenors were dilatory in contesting the recovery of QF costs given the fact that they had routinely received detailed information concerning the company's FCAC calculations. In that vein, SPS argues that where an agreement involves repeated occasions for performance by either party and the other party has knowledge of the nature of the performance and opportunity for objection, any course of performance accepted or acquiesced without objection is given great weight in the interpretation of the agreement.[272]

4. Commission Determination

140. The Commission agrees with the ALJ that SPS was permitted, as a result of the settlement in Docket No. EL89-50-000 and subsequent agreements with its wholesale customers, to collect energy-related costs of its QF purchases at or below its avoided variable energy costs, as determined by state regulatory authorities. The settlement makes clear that the costs should be included. While the contracts were modified after the settlement and therefore the context of the purchases was changed, the repeated performance of the contract without any objection by the customers establishes a course of performance that leads us to interpret the settlement as including such costs.[273]

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[271] SPS Brief Opposing Exceptions at 35-38.

[272] SPS Brief Opposing Exceptions at 38 (citing *Restatement (Second) of Contracts* § 202(4) (1981)).

[273] U.C.C. § 2-208. Section 2-208 states:

> Where the contract for sale involves repeated occasions for performance by either party with knowledge of the nature of the performance and opportunity for objection to it by the other, any course of performance accepted or acquiesced in without objection shall be relevant to determine

(continued…)

B. Testing of Energy Purchased Against Hourly Avoided Costs[274]

141. FPC Order No. 517 required that the net energy cost of energy purchases could be flowed through the FCAC when such energy is purchased on an "economic dispatch basis." The issue here is whether the Commission's FCAC regulations in effect at the time required an after-the-fact hourly analysis to determine if the purchased energy costs were less than the utility's actual avoided cost for that hour.

1. Initial Decision

142. The ALJ agreed with SPS that nothing in FPC Order No. 517 requires after-the-fact testing of purchases to ensure that they were on an economic basis. The ALJ found that SPS was under no obligation to evaluate purchases on any basis other than a projected estimate of avoided cost in any given hour. The ALJ points out that the Commission changed this regime in Order No. 352 to one where recovery of energy purchases would be permitted as long as the purchased energy costs are not more than total avoided variable cost, and that this method necessarily involves an after-the-fact analysis. Therefore, the ALJ concluded that SPS properly tested its energy purchases under the prior rule, and there is no need to plan a second phase of the proceeding.

2. Briefs on Exceptions

143. Trial Staff argues that the "economic dispatch basis" language in the Commission's prior rule could be interpreted to require after-the-fact testing.[275] Trial

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> the meaning of the agreement . . . . [and that] such course of performance shall be relevant to show a waiver or modification of any term inconsistent with such course of performance.

Accord Williston Basin Interstate Pipeline Co., 64 FERC ¶ 61,121, at 61,956 (1993) (course of performance is best indicator of what parties intended); *Northern Natural Gas Co.*, 43 FERC ¶ 63,015, at 65,159 (1988) (course of performance evidence tends to be indicative of actual contract meaning); *see also* 4 SAMUEL WILLISTON, A TREATISE ON THE LAW OF CONTRACTS § 623 (3d ed. 1961) ("The practical construction placed upon a contract by the parties themselves constitutes the highest evidence of their intent that whatever was done by them in the performance of the contract was done under its terms as they understood and intended same should be done").

[274] Initial Decision at P 167-173 (Issue II.A.5).

[275] Staff Brief on Exception at 54-55.

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Staff argues that *Pennsylvania Power & Light Co.*[276] supports its position that any portion of an economy purchase that passes through the FCAC must be tested after-the-fact each hour to determine if it is less than the utility's actual avoided cost for that hour. While Trial Staff's witness Sammon testified that the plain meaning of the Commission's prior rule suggests before-the-fact determination, Trial Staff nevertheless argues that the Commission has required after-the-fact confirmation.[277]

144. CCG argues that the ALJ erred in accepting SPS' use of a projected estimate of avoided cost in any given hour in evaluating purchases.[278] CCG cites *Philadelphia Electric Company*,[279] in which the Commission held that under Philadelphia's FCAC "the energy charge in each hour *must be less* than Philadelphia's alternate cost *in that hour*."[280] CCG adds that if SPS were not required to make hourly comparisons of its actual costs and avoided costs, the FCAC could have generated a windfall for SPS by the use of a faulty forecast or estimate. Accordingly, CCG concludes that the Initial Decision should be reversed and the Commission should direct that an appropriate redetermination or purchase eligibility be performed based on actual hour-by-hour costs.[281]

3. Brief Opposing Exceptions

145. SPS argues that the reference to "purchased on an economic dispatch basis" in its former FCAC was a reference to dispatching decisions to select those resources that would provide the lowest cost of energy in the next hour.[282] Such decisions are necessarily based on a comparison of the cost quoted for an energy purchase against the *anticipated* cost of the resources that otherwise would be used to provide the same energy if the purchase were not made. Therefore, SPS asserts that Trial Staff's interpretation of the "purchased on an economic dispatch basis" language is incorrect. SPS concedes that it did not perform after-the-fact testing under its former FCAC but holds that such testing was not required. SPS adds that since CCG did not make a valid showing that SPS'

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[276] 6 FERC ¶ 61,036, at 61,078 (1979) (*Pennsylvania Power*).

[277] Trial Staff Brief on Exceptions at 55 n.164.

[278] CCG Brief on Exceptions at 43-46.

[279] 57 FERC ¶ 61,147, at 61,564-65 (1991), *reh'g denied*, 58 FERC ¶ 61,060 (1992) (*Philadelphia Electric*).

[280] 57 FERC ¶ 61,147 at 61,564-5 (emphasis added).

[281] CCG Brief on Exceptions at 45-46.

[282] SPS Brief on Exceptions at 26-29.

energy purchases were uneconomic, there is no reason why SPS should be put to the significant burden of further analyzing its past purchases under its former FCAC.[283]

4. Commission Determination

146. We affirm the ALJ's conclusion that the plain meaning of the Commission's prior rule suggests before-the-fact determination, and we reject the contention that the Commission's prior rule required after-the-fact confirmation. Specifically, the prior rule states that "[f]uel [c]osts (F) shall be the cost of . . . the net energy cost of energy purchases, exclusive of capacity or demand charges, when such energy is purchased on an economic dispatch basis." We agree with SPS that "purchased on an economic dispatch basis" implies that a dispatch decision is to be made at the time of the dispatch. Such a decision can only be made prior to dispatch and as such can only be made based on the expected costs. If after-the-fact information were required, then "economic dispatch" would not be possible. SPS followed the plain meaning of the Commission's regulations in this regard, and we are not persuaded to require a reexamination in this case.

147. Trial Staff and CCG incorrectly argue that the Initial Decision erred in finding that SPS' prior fuel clause was consistent with the Commission's prior fuel clause regulations. CCG cites two cases, *Pennsylvania Power* and *Philadelphia Electric* as undercutting the Initial Decision's determination that the prior fuel cost regulation does not require an after-the-fact determination of energy purchases against hourly avoided cost. CCG states that *Pennsylvania Power* stands for the proposition that "the purpose of [the Commission's former] fuel clause is to pass on to customers the increases or decreases in fuel costs *actually* incurred by the utility."[284] Moreover, CCG asserts that *Philadelphia Electric* can be read to require an hour-by-hour comparison of the actual cost of the purchased energy and the cost that would have been incurred in that hour if the purchase had not been made. CCG implies that this determination could only be made after-the-fact. Trial Staff similarly argues that *Pennsylvania Power* supports an after-the-fact confirmation of whether costs related to a claimed economic dispatch are recoverable under the old fuel clause. We disagree. As stated above, in interpreting the old fuel cost regulation, *Pennsylvania Power* explains that the purpose of the old

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[283] SPS notes that, in Order No. 352, the Commission specifically found that system lambda data, which CCG witness Daniel purported to use to test whether SPS' energy purchases were economic, are not an accurate measure of avoided costs. SPS Brief Opposing Exceptions at 29 (citing Order No. 352 at 30,803).

[284] CCG Brief on Exceptions at 44 (quoting *Pennsylvania Power*, 6 FERC ¶ 61,036 at 61,078 (emphasis in original)).

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regulation is to ensure that utilities recover their actual fuel costs, i.e. to make them whole for increased fuel costs. It does not endorse an after-the-fact determination. Nor does *Philadelphia Electric* speak directly to the question of whether an economic dispatch decision is to be evaluated after-the-fact. In any event, the after-the-fact test to which CCG alludes and Trial Staff advocates was not adopted by the Commission until Order No. 352, which does not govern SPS' prior fuel clause.[285]

C. TUCO, Inc. Coal Contract[286]

148. CCG alleged that SPS engaged in a complex arrangement for the purchase of coal for its Harrington station that resulted in wholesale customers paying a higher amount for coal than if SPS had dealt directly with its affiliate Northern States Power Co. (NSP). Instead of procuring coal for its Harrington and Tolk stations through NSP, according to the record, SPS secured coal pursuant to long term supply contracts with TUCO, Inc. (TUCO), an unaffiliated corporation, which in turn was instructed to solicit bids on SPS' behalf. CCG contends that, although Peabody Coal Sales won the TUCO contract to supply SPS, the coal ended up coming from NSP through a swap, and that this could have been done at lower cost had SPS gone to NSP directly.

1. Initial Decision

149. The ALJ concluded that SPS adequately and convincingly explained that ratepayers paid no more than the market price for the coal that TUCO supplied.[287] The ALJ bases his conclusion on the fact that SPS had an exclusive requirements contract with TUCO for Harrington's and Tolk's coal needs, which precluded SPS from dealing directly with NSP.[288] The ALJ points out that SPS ended up benefiting from this

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[285] In contrast to FPC Order No. 517, the Commission's Order No. 352 regulations allow the recovery of the energy-related costs of a purchase, even if not economic in every hour in which the energy is purchased, so long as over the duration of the transaction the sum of the energy purchase costs are not more than the total costs of alternative energy avoided by the purchase. See 18 C.F.R. § 35.14(a)(2)(iv). "After-the-fact" comparisons of energy purchase costs to avoided costs must necessarily be made to ascertain whether the aggregate costs of energy purchased over the duration of the transaction are less than the costs that the transaction allowed the utility to avoid. This is not the case, however, under SPS' prior fuel clause.

[286] Initial Decision at P 174-178 (Issue II.A.6).

[287] *Id.* P 178.

[288] *Id.* (citing Ex. SPS-71 at 5-6).

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transaction due to a reduction in the market price of the coal during the course of the transaction.[289]

2. Brief on Exceptions

150. On exception, CCG states that, although TUCO had the requirements contract to supply the stations in question, SPS had the ability to exercise significant control over TUCO in this regard.[290] The CCG explains that a single person was responsible for purchasing coal for both SPS and NSP, and that, because this person knew that SPS needed coal and NSP had contract rights to purchase coal, TUCO should have been directed to deal directly with NSP.

151. CCG argues that Peabody won the contract by bidding coal that was of a lower quality than that offered by other bidders even after SPS personnel expressed concern about the coal's quality. According to the CCG, Peabody ended up providing the very coal to which NSP had option rights, and that this set of transactions resulted in SPS paying a higher price than it would have paid had TUCO been directed to purchase the proper quality coal from NSP in the first place.[291] The CCG argues that the ALJ was incorrect in concluding that SPS did not overpay for coal because the price SPS paid included a multi-million dollar premium TUCO added to the price that NSP paid under its option.[292]

3. Brief Opposing Exceptions

152. SPS responds that CCG does not adequately explain its claim that SPS overpaid for the coal, and that the Initial Decision should be sustained.[293] SPS reiterates that TUCO is a non-affiliated coal supplier which has the exclusive right to provide coal for the stations in question. SPS explains that under these contracts, TUCO arranges for purchasing, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to the station bunkers to meet SPS' requirements. TUCO also is responsible for negotiating and administering contracts with coal suppliers, transporters, and handlers.

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[289] *Id.*

[290] CCG Brief on Exceptions at 46-49.

[291] *Id.* at 48.

[292] *Id.* at 49.

[293] SPS Brief Opposing Exceptions at 29-33.

153. SPS explains that the transaction in dispute arose out of a coal price spike in 2000-2001. SPS states that its demand and risk analysis prompted it to encourage its coal supplier to secure coal for the coming years. SPS explains that TUCO accepted a bid from Peabody for 8475 Btu/lb coal from the Caballo mine (SPS states that Caballo coal had been used successfully at the SPS plant). Although plant personnel expressed concern about the Btu content of the coal, SPS states that the purchase was subject to a test burn and that there would be provisions in the contract should the coal cause problems. SPS states that it eventually asked TUCO to procure coal having a higher heating value at the urging of SPS plant personnel, which almost entirely replaced the original lower Btu coal.

154. SPS states that the transactions neither disadvantaged SPS' ratepayers nor effected a windfall to NSP or its parent Xcel Energy Inc. In fact, according to SPS, SPS' ratepayers benefited because by the time the swap for higher Btu coal was negotiated, prices had fallen from the time the original award was made for the lower Btu coal. This resulted in ratepayers paying the same price for higher quality coal that had originally been agreed to be paid for lower Btu coal.[294]

155. SPS further states that any margin that NSP earned on its option coal was passed on to its retail ratepayers. SPS summarizes its position by stating that it was required to purchase coal through TUCO, that TUCO prudently followed a request for proposal process. Thus, SPS concludes, the ALJ's findings were supported by substantial evidence and should be affirmed.[295]

4. Commission Determination

156. The Commission affirms the Initial Decision in this regard. In its brief on exceptions, CCG does not provide evidence demonstrating that SPS paid more through the Peabody swap than NSP could have paid at the outset. But even if the CCG did show that, in hindsight, higher quality coal could have been purchased for less, SPS' exclusive contract with TUCO obligated TUCO to solicit bids and a decision was made to purchase the lower cost Peabody coal and blend it with higher quality coal, in the hopes of a lower cost of coal. The coal decision was a judgment call that SPS and its parent corporation made, and the Commission is not persuaded to reverse the ALJ's finding that SPS' activity was just and reasonable.

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[294] *Id.* at 32.

[295] *Id.* at 33.

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V. SPS' Proposed FCAC in Docket No. ER05-168-000

157. On November 2, 2004, the same date CCG filed its complaint against SPS, SPS filed a proposal under section 205 of the FPA to change its FCAC and to make corresponding revisions to SPS' power supply contracts. SPS stated that it filed the revised FCAC to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations,[296] and also to account for expenses and revenues associated with SPS' participation in the SPP OATT. The proposed FCAC is subject to the Commission's current FCAC policy as set forth in Order No. 352, *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*.[297] According to Order No. 352, the Commission's *pro forma* FCAC allows electric utilities to recover all expenses associated with purchased power through fuel clause adjustments if two conditions are met. First, the total cost of the purchase must be less than the buyer's total avoided variable cost and the purchase must be of less than twelve months duration. And second, the purpose of the purchase must be solely to displace higher cost generation.[298]

158. On December 29, 2004, the Commission accepted and suspended, for a nominal period, subject to refund, SPS' proposed changes in the FCAC.[299] The Commission also consolidated SPS' proposed FCAC changes with the proceeding already underway in the complaint case before an ALJ in Docket No. EL05-19-000.

159. The following issues are in dispute regarding SPS' proposed FCAC: recovery of energy related costs (specifically long-term QF purchases, wind energy purchases); transmission costs; FCAC protocols; wind energy costs; avoided variable costs; and a separate QF provision.

A. Energy Related Costs

160. The issue here is whether the FCAC SPS proposes complies with the Commission's regulations governing the recovery of costs associated with long-term QF purchases and wind energy purchases. The ALJ determined that the proposed FCAC is consistent with the Commission's FCAC regulations.

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[296] Order No. 352.

[297] FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

[298] Order No. 352 at 30,799.

[299] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004).

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1. Long-Term QF Purchases[300]

a. Initial Decision

161. Noting that SPS agreed to amend its FCAC to include only energy charges associated with QF energy purchases on a going-forward basis, the ALJ concluded that this satisfactorily resolves the issue.[301] The ALJ concluded that a reading of the plain language of 18 C.F.R. § 35.14(a)(2)(iv) contemplates inclusion of energy charges if the total of such charges is less than the buyer's total avoided variable costs, with no distinction made between short and long-term contracts. In the ALJ's words, "[t]hat's what the regulation requires and that's what ought to be in the Company's FCAC."[302]

b. Briefs on Exceptions

162. CCG argues that the ALJ erred in failing to consider that Order No. 352 does not allow FCAC treatment for non-fuel energy costs or recovery of fuel costs for purchases greater than one year in duration that are maintained for reliability reasons.[303] CCG asserts that SPS' version of the FCAC improperly eliminates the limitations contemplated by Order No. 352, and that therefore the Commission should reverse the ALJ on this issue.

c. Briefs Opposing Exceptions

163. SPS cites Order No. 352, in which the Commission stated, in part, "[w]e have added the phrase "for any purchase" [to the FCAC], which allowed *energy charges only* to be recovered through fuel clause adjustments."[304] SPS argues that the Commission used the phrase "energy charges only" to distinguish the costs that were allowed to be recovered under section 35.14(a)(2)(iv) from the "total costs of the purchase of economic power" that are authorized for FCAC recovery under section 35.14(a)(2)(iii).[305] SPS argues that recoveries under the latter section are subject to two tests. First, the economic test compares the total cost of the purchase (including capacity and transmission

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[300] Initial Decision at P 179-185 (Issue II.B.1).

[301] *Id.* P 183.

[302] *Id.* P 183.

[303] CCG Brief on Exceptions at 50-55.

[304] SPS Brief Opposing Exceptions at 40 (citing Order No. 352 at 30,809) (emphasis added by SPS).

[305] *Id.* at 40.

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charges)[306] to the total avoided cost over the purchase. Second, the regulation requires that the "economic power" purchase be for a period of twelve months or less.[307]

164. In contrast, SPS argues that recovery of *energy charges only* is not limited to energy purchases made under contracts with terms of twelve months or less; energy charges for *any purchase* may be recovered so long as they are less than avoided costs over the duration of the transaction, however long it may be. Therefore, SPS argues that the ALJ correctly found that "energy only costs" are eligible for recovery under section 35.14(a)(2)(iv) and are not subject to the reliability criterion.[308]

165. Trial Staff argues that the Initial Decision correctly reads Commission FCAC regulation 35.14(a)(2)(iv) and should be affirmed on this issue. The Initial Decision held that the plain language of regulation 35.14(a)(2)(iv) permits recovery of energy charges, including non-fuel energy charges, associated with purchase power contracts of one year or greater duration.[309] Indeed, section 35.14(a)(2)(iv) provides for FCAC pass through of

> Energy charges for *any purchase* if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost . . . . (emphasis added by trial staff).

166. Trial Staff states that according to the Initial Decision, "any purchase" in section 35.14(a)(2)(iv) means "any purchase." That includes purchases pursuant to purchased power contracts of one year or greater duration. The regulation clearly does not say "any purchase of less than one year duration," according to Trial Staff.

d. Commission Determination

167. The Commission agrees with the ALJ that energy charges can be included in the FCAC as long as the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. CCG's argument that Order No. 352 imposes two limitations appears to be a misunderstanding of the terms "total costs of the purchase of economic power" and "energy charges only." The Commission's regulations clearly provide that the total costs of purchases of economic power can be flowed through the FCAC only if the purchases are both economic and less than twelve months in

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[306] *Id.* (citing 18 C.F.R. § 35.14(a)(11)(ii) (2007)).

[307] *Id.* (citing 18 C.F.R. § 35.14(a)(11)(i) (2007)).

[308] *Id.* at 41.

[309] Trial Staff Brief Opposing Exceptions at 36-40.

duration. However, the purchase duration under section 35.14(a)(2)(iii) does not apply to purchases under section 35.14(a)(2)(iv). Thus, the energy charge portion (including non-fuel energy charges) of power purchases can be flowed through the FCAC regardless of the length of the contract as long as the purchased power price is less than total avoided variable costs.

2. Wind Energy Purchases[310]

168. The issue here is whether SPS' proposed FCAC permits SPS to recover the energy-related costs of all of its wind energy purchases.

a. Initial Decision

169. In its proposed FCAC, SPS originally sought to include the total cost of energy purchases, as long as they were less than the total avoided costs during the purchase period. SPS agreed to revise the language of section 2(iv) of its FCAC to refer only to energy charges incurred for wind energy purchases. The ALJ determined that this resolved the issue.

b. Briefs on Exceptions

170. CCG states that the record demonstrates that SPS' wind purchases are long-term purchases that are factored into SPS' planning forecasts as capacity resources. CCG points out that in SPS' proposed FCAC, SPS seeks FCAC recovery of energy costs associated with all wind energy purchases "without limitation" of total energy costs and "over the term of the purchase."[311] CCG asserts that Order No. 352 states that "purchases

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[310] Initial Decision at P 186-190 (Issue II.B.2). This section also addresses Issue II.B.5 of the Initial Decision, at P 200 (Should SPS be permitted to recover the energy-related cost associated with long-term (one year or more) purchases if such purchase costs are less than the avoided cost over the term of the contract?).

[311] Ex. SPS-2, section 2(iv) (emphasis added) provides:

> [E]nergy charges for any *purchase including, without limitation, the total energy costs associated with purchases from any wind energy projects* to the extent that the energy related charges incurred for the purchase *over the term of the purchase* are less than the Company's total avoided variable costs. For energy purchases greater than one year, the Company will measure the monthly purchase price relative to the Company's total monthly avoided variable cost. The Company will only include in the FCA the lesser of the

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longer than a year are bound to have some reliability benefits . . . . We want only purchase expenses made solely for economy purposes to be passed through the fuel clause . . . [E]xpenses for purchases longer than one year can be estimated in rate cases."[312]

171. CCG argues that because SPS' wind purchases are long-term, SPS should not be permitted to recover energy costs associated with these purchases through the FCAC. CCG adds that wind purchases by definition have no fossil fuel costs, so wind costs should be recovered through base rate.[313]

172. PNM argues that section 2(iv) of SPS' proposed FCAC should be modified to delete references to wind energy purchases in order to ensure that such purchases are treated consistently with other purchases for purposes of FCAC recovery.[314]

c. Brief Opposing Exceptions

173. SPS states that in referencing wind purchases it is only pointing out that wind purchases are part of the subset of energy purchases addressed by section 2(iv) of its proposed FCAC. SPS argues that, consistent with Order No. 352, it may recover such associated energy costs, provided that these are less than avoided variable costs over the term of the purchase. SPS believes that the ALJ's findings should be affirmed.[315]

d. Commission Determination

174. In considering above the issue of SPS' recovery of the energy related costs of purchases from QFs under long-term contracts under SPS' proposed FCAC, we agreed with the ALJ that energy charges can be included in the FCAC only where the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. Similarly, the Commission agrees with the ALJ that SPS' recovery of the energy-related costs of all wind energy purchases is permissible when the total of such charges is less than the buyer's total avoided variable cost.

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cumulative purchase price or the total avoided variable cost incurred through the term of the purchase to date.

[312] CCG Brief on Exceptions at 51 (citing Order No. 352 at 30,802).

[313] *Id.* at 55-57.

[314] PNM Brief on Exceptions at 5-7.

[315] SPS Brief on Exceptions at 41-42.

175. In addition, with regard to whether SPS should be permitted to recover the energy-related costs associated with long-term (one year or more) purchases if such purchase costs are less than the avoided cost over the term of the contract, we also find that SPS is permitted to recover the energy-related costs as long as they are less than the avoided variable costs as governed by section 35.14(a)(2)(iv). We reach this conclusion because the regulation states that energy charges for any purchase may be included as long as those charges are less than the total avoided variable costs.

3. Aggregation of Wind Energy Purchases[316]

176. CCG asserts that SPS attempts to enhance its treatment of wind energy purchases by not testing each single wind purchase, or any "forward purchase," on a purchase-by-purchase basis, but bundling them together for economic evaluation in its after-the-fact analysis.[317] CCG claims that this is a violation of the Commission's FCAC regulations which, CCG asserts, requires that the purchases be measured individually.

177. Section 35.14(a)(2)(iv) reads as follows:

> 2. Fuel costs (*F*), measured in $, shall be the cost of:
>
> * * *
>
> (iv) Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost[318]

a. Initial Decision

178. The ALJ found that, due to the time-consuming nature of doing individual contractual analysis, SPS' practice of aggregating the wind purchases for economic test purposes is justified.[319] The ALJ adds that while a literal reading of the Commission's FCAC regulations does not contemplate aggregation of wind purchases, the use of "short-cuts" to avoid the unnecessary expense and burden of implementing certain provisions is acceptable, especially when there is no specific prohibition of such practices.[320]

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[316] Initial Decision at P 191-194 (Issue II.B.3).

[317] Initial Joint Brief of CCG at 64.

[318] 18 C.F.R. § 35.14(a)(2)(iv) (2007).

[319] Initial Decision at P 194.

[320] *Id.*

b. Briefs on Exceptions

179. Trial Staff argues that the regulation clearly intends that wind energy purchases must be evaluated on a purchase-by-purchase basis to qualify for FCAC treatment. According to Trial Staff, the plain language of Commission regulation 35.14(a)(2)(iv) states that added to energy charges passed through the FCAC will be "energy charges for *any purchase* if the total amount of energy charges incurred for *the purchase* is less than the buyer's total avoided variable cost."[321] Trial Staff argues that the use of the singular number demonstrates that the regulation intends that each individual purchase be evaluated against SPS' total avoided variable cost. Therefore, Trial Staff concludes that aggregating purchases for evaluation purposes violates the regulation.[322]

180. CCG states that the Commission's regulations contemplate that utilities will make economic decisions about each of their purchases, consistent with the requirements of FPA section 205(f).[323] CCG states that neither SPS nor the Initial Decision cited precedent or regulation that supports aggregation of purchases.[324]

181. PNM also argues that the language in section 35.14(a)(2)(iv) of the Commission's regulations indicates that, in order to evaluate whether a given purchase may be flowed through the FCAC, it is necessary to examine whether that purchase—in and of itself, and not in conjunction with other purchases—is economic. Therefore, PNM asserts that the Initial Decision permitting aggregation should be reversed.[325]

c. Brief Opposing Exceptions

182. SPS argues that the practical implementation of its FCAC provisions by aggregating wind energy purchases was sensible and not in violation of the Commission's regulations. SPS adds that in any month typically wind energy costs will be substantially less than avoided costs. Therefore, SPS asserts, the ALJ was correct in

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[321] 18 C.F.R. § 35.14(a)(2)(iv) (2007) (emphasis added).

[322] Staff Brief on Exceptions at 60.

[323] 16 U.S.C. § 824d(f) (2000) (requiring that "not less than every four years the Commission shall make a thorough review of automatic adjustment clauses in public utility rates").

[324] CCG Brief on Exceptions at 59.

[325] PNM Brief on Exceptions at 7-9.

determining that SPS' practice of aggregating wind energy purchases would reduce expense and burden in administering its FCAC, and this determination should be affirmed.[326]

d. Commission Determination

183. The Commission will reverse ALJ on this issue. The language of our regulation refers in the singular to "any purchase" and "the purchase."[327] This regulation thus requires a purchase-by-purchase analysis, as opposed to aggregate analysis. Administrative convenience notwithstanding, counting purchases individually serves a purpose that aggregation would not. This is illustrated by the following scenario:

> Assume that SPS purchases 100 MWh of wind energy at $30/MWh in a month when avoided costs are $40/MWh. Under the Initial Decision approach, SPS in effect would bank $1,000 ($10/MWh times 100 MWh hours) that it could net against future purchases that would otherwise be uneconomic and therefore ineligible for fuel clause recovery. Were this to happen for the first six months of a contract, SPS would have banked $6,000. In subsequent months, SPS would be able to purchase well above avoided costs but nevertheless recover all of its costs through the FCAC by aggregating over the contract life. For example, in the next six months SPS could purchase 100 MWh at $50/MWh, assuming avoided costs remain at $40, and still flow costs through the FCAC.[328]

The Commission's interpretation prevents abuse of the system which could occur if a utility was permitted to aggregate purchases. Further, we do not believe that performing a purchase-by-purchase analysis as required by the FCAC would place an undue administrative burden on SPS.

184. When the Commission interprets its own regulations, "a court must necessarily look to the administrative construction of the regulation if the meaning of the words used

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[326] SPS Brief Opposing Exceptions at 43-44.

[327] *Cf.* Holder v. Hall, 512 U.S. 874, 918 (1994) (Thomas, J., concurring) (explaining that the words "any citizen" refers to individual citizens).

[328] Occidental Brief on Exceptions at 10. While Occidental settled with SPS in this proceeding, Occidental's Brief on Exceptions is still a part of the record and as such, the Commission relied upon the brief in making its decision.

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is in doubt. . . . The ultimate criterion is the administrative interpretation, which becomes of controlling weight unless it is plainly erroneous or inconsistent with the regulation."[329]

B. Transmission Costs[330]

185. SPS proposes to recover, through its proposed FCAC, the cost of transmission losses purchased from SPP, less the payments for transmission losses that it receives from SPP. It claims the right to do this by virtue of 18 C.F.R. § 35.14(a)(4), which provides that "[t]he adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale."

1. Initial Decision

186. In the Initial Decision, the ALJ determined that it would be unfair to allow SPS to recover the cost of transmission losses purchased from SPP, less the payments for transmission losses that it receives from SPP, through its proposed FCAC because SPS cannot ensure that they are related to the wholesale sales.[331] No briefs on exceptions were filed on this issue.

2. Commission Determination

187. We affirm the ALJ's ruling to prohibit SPS from recovering net transmission losses through the FCAC for the reasons given by the ALJ as described above. Section 35.14(a)(4) of the Commission's regulations provides that the FCAC adjustment factor "shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale." Because SPS admittedly cannot identify each transaction for which SPS is charged a loss, we agree with CCG that SPS has failed to demonstrate that the losses paid actually relate to services provided to the customers at issue or any wholesale sales.

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[329] *Udall v. Tallman*, 380 U.S. 1, 16-17 (1965).

[330] Initial Decision at P 195-199 (Issue II.B.4).

[331] Tr. 1966 (Hudson).

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C. FCAC Protocols[332]

1. Initial Decision

188. The ALJ found that there should be a set of protocols as part of the filed rate that explain in detail how SPS will implement its proposed FCAC on a monthly basis.[333] To accomplish this, the ALJ recommended that the parties form a study group to identify the new information and protocols that will provide the additional support for the FCAC calculations and billings necessary to obtain a greater understanding of the costs included in the charges.

2. Brief on Exceptions

189. SPS argues that the protocols requirement modifies and amends the Commission's FCAC regulations and that this would necessitate a notice and comment rulemaking to implement the FCAC protocol requirement.[334] SPS cites *American Federation of Government Employees, Local 3090 v. Federal Labor Relations Authority*[335] and *Consumer Energy Council of America v. FERC*[336] in support of its position.[337] SPS also argues that the evidence does not support the need for the addition of elaborate protocols to the FCAC provisions of SPS' wholesale rate schedules. SPS states that the evidence cited by the ALJ in support of the protocols does not actually support the ALJ's decision.[338] In fact, SPS argues, the discovery of the error in the preparation of one month's FCAC by a Golden Spread employee actually demonstrates SPS' customers' thorough understanding of SPS' FCAC charges as they would not have caught the error otherwise.

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[332] Initial Decision at P 201-204 (Issue II.B.5).

[333] *Id.* P 204 (adopting CCG's position as described in P 201).

[334] SPS Brief on Exceptions at 75-76.

[335] 777 F.2d 751, 759-60 (D.C. Cir. 1985).

[336] 673 F.2d. 425, 446 (D.C. Cir. 1982).

[337] SPS Brief on Exceptions at 75-76.

[338] The evidence cited includes: (1) an error in the preparation of one month's fuel clause calculations related to the inadvertent exclusion of clearly eligible costs; and (2) the restatement of fuel charges for another month in order to take into account new information not available at the time of the original calculation.

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190. Lastly, SPS argues that it already provides extensive information to its wholesale customers detailing the FCAC calculations. SPS states that its practice is to provide information in a timely manner whenever customers contact SPS with questions or concerns about its FCAC calculations.

3. Briefs Opposing Exceptions

191. Trial Staff argues that the Initial Decision correctly ruled that SPS and its customers should form a study group to develop and recommend to the Commission detailed protocols to clarify and complete the proposed FCAC rate schedule at issue in this case. Trial Staff points out that section 205(c) of the FPA imposes an obligation upon SPS to ensure that its rate schedules are in a form that facilitates inspection and monitoring by the public and investigation by the Commission's auditors.[339] Unclear and incomplete rate schedules frustrate those rights. In particular, Trial Staff states that when SPS uses a complex computer model to determine whether the energy charges of a purchase that it has "incurred" are valid under the proposed FCAC – a determination that the current FCAC regulation requires – it is reasonable to conclude that the operation of the model should be explained in the rate schedule. The explanation should be in protocols, according to Trial Staff. The Initial Decision, therefore, should be affirmed.

4. Commission Determination

192. The Commission will not adopt the ALJ's recommendation that SPS be required to file detailed protocols as part of its proposed FCAC. Because the rates established in the instant proceeding are for a locked-in period (January 1, 2005 to July 1, 2006), the issue of SPS establishing protocols to explain how it will implement its proposed FCAC on a monthly basis is moot. SPS recently filed a rate case in Docket No. ER08-749-000 and it included protocols in that filing. The Commission will have the opportunity to address the adequacy of SPS's protocols in that proceeding.

193. However, as a safeguard, we will direct that SPS make an informational filing two years from implementation of its new FCAC. SPS should include sufficient detail through narrative and comparative numbers to enable the Commission to evaluate SPS' treatment of fuel for its market-based rate sales for compliance with the Commission's directives herein and to assure the Commission that it is not aggregating its wind energy purchases (as discussed above) for the purpose of fuel clause calculations to its wholesale customers. While we will not mandate fuel clause protocols, we encourage SPS to be responsive to any customers' concerns with respect to implementation of the FCAC.

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[339] 16 U.S.C. § 824d(c) (2000).

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D. Wind Energy Costs[340]

1. Initial Decision

194. The ALJ determined that SPS' mention of wind energy costs in its FCAC is consistent with the Commission's FCAC regulation, which allows energy charges associated with any purchase to be recovered through the FCAC if such charges are less than the buyer's total avoided cost over the purchase period. No briefs on exception were filed.

2. Commission Determination

195. For the reasons stated above, we affirm the ALJ's ruling that section 2(iv) of the proposed FCAC is, as amended, consistent with our regulations.

E. Avoided Variable Costs[341]

1. Initial Decision

196. The ALJ found that in order for section 2(v) of SPS' proposed FCAC to be consistent with the Commission's current FCAC regulations, SPS must conduct an after-the-fact comparison of actual avoided costs against the purchase costs.[342] No briefs on exceptions were filed.

2. Commission Determination

197. The Commission affirms the ALJ's conclusion because our FCAC regulations permit the flow through of "avoided variable costs," and an after-the-fact test is necessary to make this determination.

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[340] Initial Decision at P 208-212 (Issue II.B.10).

[341] *Id.* P 213-217 (Issue II.B.11).

[342] *Id.* P 217.

F. Separate QF Provision[343]

1. Initial Decision

198. The ALJ determined that there was nothing wrong with SPS' inclusion of a separate provision regarding QF purchases in its proposed FCAC because the energy-related costs of any purchase are eligible for FCAC recovery, so long as they are less than the buyer's total avoided variable cost. The ALJ found fault with the language used by SPS in the proposed FCAC regarding the appropriate test to ensure that the energy-related costs of the QF purchases are less than the buyer's total avoided variable costs. The ALJ determined that SPS must change its language to specify an after-the-fact analysis to support recovery of such costs via the FCAC. No briefs on exception were filed.

2. Commission Determination

199. In considering above the issue of SPS' recovery of the energy related costs of purchases from QFs under long-term contracts under SPS' proposed FCAC, the Commission agreed with the ALJ that energy charges can be included in the FCAC if the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. Therefore, the Commission agrees with the ALJ that SPS' inclusion in its proposed FCAC of a separate provision regarding QF purchases is consistent with the Commission's regulations.

200. With regard to the language in the FCAC referring to the buyer's total avoided variable cost, the Commission agrees with the ALJ that SPS must change its language to specify an after-the-fact analysis to support recovery of such costs via the FCAC, instead of using state authority estimates.

VI. Refunds to Cap Rock

201. Because Cap Rock is not a formal complainant but an intervenor in this docket, the question arises as to its rights to refunds as a full requirements customer of SPS.[344]

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[343] *Id.* P 218-221 (Issue II.B.12).

[344] On December 2, 2004, Cap Rock filed a pleading captioned "Motion to Intervene" in the complaint docket, but in the body of the motion it wrote that it was submitting the motion also as a complaint under section 206 of the FPA. The Commission granted Cap Rock intervenor status in its order establishing hearing and settlement procedures. Cap Rock subsequently requested clarification of its intervenor status. In an order issued May 2, 2006, the Commission clarified that Cap Rock is an

(continued…)

Even though Cap Rock is not a complainant, this neither prevents Cap Rock from receiving refunds, nor does it prevent its rates from being subject to the full requirements rates after the refund effective date. When the same customer class and the same rates are at issue, a separate complaint is not required for refunds to apply to all customers served under that rate.[345] Cap Rock pays the same charges that the full requirements customers pay and SPS admits that it groups them with the other full requirements customers when setting rates.[346] Accordingly, Cap Rock is entitled to refunds consistent with the outcome of the compliance phase in this case.

VII. Post-Hearing Motions

A. Background

202. On June 23, 2006, the day that briefs on exceptions to the Initial Decision were due, West Texas Municipal Power Agency (West Texas) filed a Motion to Intervene Out-of-Time. Citing section 214(d) of the Commission's Rules of Practice and Procedure,[347] West Texas states that it meets the Commission's standards for late intervention, namely: (1) West Texas has good cause for not seeking to intervene earlier; (2) West Texas' intervention will cause no disruption in this proceeding; (3) it has become apparent that West Texas' interests are not being adequately represented by any other party to this proceeding; and (4) West Texas' intervention will not prejudice, or impose additional burdens on, any party.[348] West Texas states that it is a long-term firm power supply purchaser from SPS, with fuel costs calculated on an average system basis for many years and, in this respect, is similarly situated to the complaining cooperatives in this proceeding.[349]

203. On July 10, 2007, PNM filed an answer in opposition to West Texas' motion to intervene. PNM asks the Commission to deny West Texas' motion citing the late stage

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intervenor, not a party complainant. That order did not address whether any relief that might eventually be granted would apply to Cap Rock. *See Golden Spread Elec. Coop., Inc*., 115 FERC ¶ 61,136 (2006).

[345] *See, e.g.*, *North Carolina Elec. Membership Corp.*, 57 FERC ¶ 61,332, at 62,067 (1991).

[346] Initial Decision at P 234.

[347] 18 C.F.R. § 385.214(d) (2007).

[348] West Texas Motion to Intervene at 1.

[349] *Id.* at 4.

of the proceeding, the prejudice to parties who intervened and participated in a timely manner, and West Texas' failure to articulate a reason why it should be permitted to intervene at this stage or why it failed to do so earlier.

204. On July 17, 2006, SPS filed an answer to the answers opposing West Texas' motion to intervene. SPS restates West Texas' arguments.[350]

205. On the same day that West Texas filed its motion, El Paso Electric Company (El Paso), filed a four-page letter to the Commission commenting on the Initial Decision. On June 30, 2006, CCG filed a motion to reject El Paso's comments, arguing that El Paso lacks standing to make a filing because it is not a participant, as defined by rule 711 of the Commission's Rules of Practice and Procedure,[351] and thus is not permitted to file what is essentially a brief on exceptions. On July 10, 2006, PNM filed a motion to strike El Paso's submission. PNM argues that El Paso is a non-party to this proceeding and that El Paso's letter is "in blatant disregard for the Commission's rules governing the submission of evidence" and "will violate the due process rights of parties" to this proceeding.[352]

206. On July 17, 2006, SPS filed an answer in support of El Paso's comments. SPS reiterates El Paso's comments, and argues that the letter should be considered a proper submission "by a member of the public."[353] SPS further argues that there is no prohibition on the Commission "merely receiving extra-record communications, as long as they are made available to the public and served on the parties."[354] SPS moves that the Commission reopen the record to accept El Paso's comments as a response to hearsay and to permit a response by PNM.[355]

207. On August 1, 2006, PNM filed a motion for leave to respond and a response to SPS' answer. PNM argues that El Paso's comments are not proper comments submitted by a member of the public, that the letter is not a proper response to alleged hearsay testimony, and that the record should not be reopened under rule 716.

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[350] SPS Answer at 5-6.

[351] 18 C.F.R. § 385.711 (2007).

[352] PNM Motion at 1.

[353] SPS Answer at 6.

[354] *Id.* at 6-7.

[355] *Id.* at 7-8.

B. Commission Determination

208. The Commission will reject West Texas' motion to intervene out-of-time.[356] West Texas filed its motion after issuance of the Initial Decision, but fails to present an adequate reason why, for a year and a half since this proceeding began, it remained silent and relied on others to defend its interests. West Texas is not free to now change its mind and conclude that the participants in the case did not live up to its expectations. West Texas cannot remain inactive throughout and then enter the proceeding following the conclusion of a full evidentiary hearing and all that it entails.[357] As we have long held, the failure of one's interests to be adequately represented can be blamed on no one but oneself.[358] West Texas made a conscious decision not to intervene earlier. It cannot be permitted to intervene at this late date and raise an issue which will cause delay in the culmination of this proceeding.[359]

209. The Commission will reject El Paso's submittal because El Paso is not a participant in this proceeding and therefore, under Rule 711, El Paso lacks the standing to make such a filing.

The Commission orders:

(A) The Initial Decision is affirmed in part and reversed in part, as described in the body of this order.

(B) SPS is directed to file, within 30 days of the date of this order, a compliance filing quantifying refunds relating to cost of service rates and FCAC billings. This filing shall include a cost of service analysis and rate design consistent with the Joint Stipulation and the Commission's findings herein.

(C) Cap Rock is entitled to refunds as described in the body of this order, with such refunds to be effective January 1, 2005.

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[356] *E.g.*, *Connecticut Yankee Atomic Power Co.*, Opinion No. 449, 92 FERC ¶ 61,269, at 61,899 (2000) (denying motion to intervene filed after issuance of initial decision for failure to demonstrate good cause and to prevent undue burden on active participants).

[357] *See, e.g.*, *DiVito v. Fidelity & Deposit Co.*, 361 F.2d 936, 939 (7th Cir. 1966) (stating that "equity aids the vigilant").

[358] *See, e.g.*, *Southwestern Pub. Serv. Comm'n*, 22 FERC ¶ 61,341, at 61,593 (1983).

[359] *Id.*

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(D) The motion to intervene out-of-time by West Texas is denied for the reasons described in the body of this order.

(E) The filing by El Paso is rejected as described in the body of this order.

By the Commission. Commissioners Wellinghoff and Kelly dissenting in part jointly with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Golden Spread Electric Cooperative, Inc.
Lyntegar Electric Cooperative, Inc.
Farmers' Electric Cooperative, Inc.
Lea County Electric Cooperative, Inc.
Central Valley Electric Cooperative, Inc.
Roosevelt County Electric Cooperative, Inc. Docket No. EL05-19-002

v.

Southwestern Public Service Company

Southwestern Public Service Company Docket No. ER05-168-001

(Issued April 21, 2008)

WELLINGHOFF and KELLY, Commissioners, *dissenting in part*:

In the initial decision in this proceeding, the Administrative Law Judge (ALJ) found that

> [t]he plain facts are that SPS improved its competitive position in making market-based sales by charging market-based customers lower system average fuel costs, and collected the difference from the Company's cost-based customers, who were forced to cover their own fuel costs and the difference between average costs and the incremental fuel costs associated with the market-based sales.[360]

The ALJ stated that the "complainants should not be foreclosed from pursuing an investigation back in time, so long as it is reasonably bounded."[361] The ALJ then determined that the relevant period for considering Southwestern Public Service Company's (SPS) fuel cost adjustment clause (FCAC) is from 1999 forward.[362]

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[360] *Golden Spread Elec. Coop., Inc.*, 115 FERC ¶ 63,043, at P 150 (2006) (Initial Decision).

[361] Initial Decision, 115 FERC ¶ 63,043 at P 125.

[362] *Id.*

Despite the ALJ's determination, today's order directs SPS to make refunds starting with the refund effective date of January 1, 2005, based on a finding that SPS' FCAC is ambiguous on the issue in dispute. We do not agree with the order's assertion that SPS' FCAC language was ambiguous as to the fact that SPS should credit incremental fuel and purchased power costs attributable to intersystem sales, rather than system average fuel costs, against the cost of fuel and purchased power recovered through the FCAC. As today's order correctly states, the Commission may "take retroactive refund action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs . . . ."[363] Therefore, we agree with the ALJ's determination, based upon his careful review of the extensive record in this proceeding, that we should direct SPS to pay refunds from 1999 to 2004. Further, consistent with the ALJ's determination, we believe that today's order should have directed SPS to make a compliance filing in order to allow the Commission to quantify what, if any, refunds are due for the period beginning January 1, 2005.[364]

Accordingly, we dissent in part from this order.

_____	_____
Jon Wellinghoff	Suedeen G. Kelly
Commissioner	Commissioner

[363] *Golden Spread Elec. Coop., Inc.*, 123 FERC ¶ 61,047, at P 53 (2008) (citation omitted).

[364] Initial Decision, 115 FERC ¶ 63,043 at P 239, 254.

Document Content(s)

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ARK. PUBLIC SERVICE COMM.
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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	**DOCKET NO. 04-176-U** **ORDER NO. 6**

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

On July 12, 2005, Staff filed the Direct Testimony and Exhibits of Gayle Freier, Senior Capital Recovery Analyst, Robert H. Swaim, Rate Analyst, Steven McGarity, Public Utility Auditor, Robert D. Booth, Manager of the Gas and Water Utility Section, Randy Kersten, Auditor, Larry Walker, Public Utility Audit Supervisor, Sandra B. Green, Rate Analyst, and Johnny Brown, Senior Financial Analyst. In addition, Direct Testimony and Exhibits were filed on that date by William B. Marcus on behalf of the AG, Christopher A. John and Raymond Reno Cassidy on behalf of the NWAGC, and William E. Tinsley on behalf of the CEUG.

On August 9, 2005, AWG filed the Rebuttal Testimony and Exhibits of witnesses Gunter, Campbell, Dr. Morin, Morgan, Stewart, Charles V. Stevens, Senior Vice President, AWG, and Dr. Kimbugwe A. Kateregga, Vice President, Foster Associates, Inc.

On September 2, 2005, Staff filed the Surrebuttal Testimony and Exhibits of witnesses Freier, Swaim, McGarity,[2] Booth, Walker, Green, Brown, Alisa Williams, Staff Auditor,[3] and Alice D. Wright, Manager Cost Allocation and Rate Design Section. Additionally, filing Surrebuttal Testimony on that date were AG witness Marcus, NWAGC witnesses Cassidy and John, and CEUG witness Tinsley. On September 15, 2005, the Supplemental Surrebuttal Testimony of AG witness Marcus was filed.

On September 19, 2005, AWG, Staff, the AG, NWAGC, and CEUG, (the "Parties") filed an *Issues List*, outlining those issues which were still contested and providing the Commission an outline of those issues on which the Parties had reached consensus ("Issues List").

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[2] Jeff Hilton, Manager of the General Staff's Audits Section, subsequently adopted Mr. McGarity's pre-filed testimonies. (Tr. at 1376-1378)

[3] Ms. Williams adopted the testimony of Staff witness Kersten.

Public evidentiary hearings were held in Little Rock, Arkansas, from September 20 through September 22, 2005, for the purpose of receiving public comments, opening statements, and litigating the issues contested by the parties in this proceeding. Additional public comment hearings within AWG's service territory were held on September 26, 2005, in Fayetteville, Arkansas, and on September 27, 2005, in Blytheville, Arkansas.

GENERAL OVERVIEW

AWG is an Arkansas corporation and a natural gas public utility under APSC jurisdiction which provides service to 144,000 customers in this state. (Application at pp.1-2) AWG and its operations in natural gas exploration and production "were transferred to separate wholly-owned subsidiaries of a newly formed, publicly owned, holding company named Southwestern Energy Company ("SWN")." (Tr. at 208) SWN provides services to its subsidiaries, the costs of which are shared by AWG and its affiliates. (Tr. at 209) AWG initially filed a non-gas revenue requirement of $60,344,518 and rate schedule revenue requirement of $58,449,249. (Tr. at 1353) The Company sought an increase in its current base rates of $9.739 million which equates to a 20% increase in those base rates or a 5.2% increase in its overall rates, inclusive of gas cost. (Application at p. 2, Tr. at 210) AWG subsequently amended its request in Surrebuttal Testimony and now seeks a non-gas revenue requirement of $58,920,973, reporting a deficiency of $7,626,351. (Tr. at 918)

In conjunction with its application, AWG filed a depreciation study (as required by the Stipulation and Agreement approved in Docket No. 02-227-U) and has used the resulting rates in support of this filing. (Application at pp. 2-3) AWG proposes no changes to customer charges, with the entire increase to be collected through the delivery charge. (Tr. at 210) AWG recommends

adoption of its cost of service, as modified to address certain allocation changes as proposed by the other parties. (Tr. at 804, Ex. at 459) As part of its application, AWG requests that the Commission "make two changes in the manner in which rates are ordinarily determined . . ." and approve "a return on equity using a blend of several methods rather than relying solely on the discounted cash flow ('DCF') method" and "a Revenue Evaluation Plan ("REP") under which AWG's rates will be evaluated annually and adjusted up or down if AWG's actual earned return on equity is 50 basis points below or above an established reasonable return." (Tr. at 210-211)

Staff has proposed in its Surrebuttal Testimony a non-gas revenue requirement of $55,591,342, resulting in a deficiency of $4,325,174 which was $3,229,631 less than AWG's current request. (Tr. at 1607-1608) Staff recommends that the proposed revenue requirement be allocated using its proposed cost of service and rates be designed using its recommendations. (Tr. at 1538-1539) AWG has adopted Staff's Cost of Service and its design of rates. Staff also recommends that equity return be determined primarily upon the results of the DCF methodology (Tr. at 652-658), subject to checks for reasonableness, including comparison to results under the risk premium method. (Tr. at 658-659) Staff also recommends that the Commission deny AWG's request for approval of its REP Rider. (Tr. at 1600)

The AG recommends that, based on a series of its proposed adjustments, AWG's initially-filed revenue requirement should be, at a minimum, reduced by $3.5 million.[4] (Tr. at 52) The AG also recommends that AWG's cost of service and proposed rate design be rejected and that the

[4]The AG does not endorse a specific revenue requirement or rate of return in its initially filed Testimony, recognizing that other adjustments recognized by it or Staff may also be applicable. (Tr. at 108, footnote 36)

Commission adopt those proposed by the AG. (Tr. at 53) The AG's proposed cost allocation differences with AWG are related to production (Tr. at 87-90, 92) and transmission. (Tr. at 90-93) For these, Mr. Marcus proposes increasing allocation based on usage rather than demand. Mr. Marcus also differs on main allocation, testifying that his preferred recommendation is that the Commission approve a zero mains allocation to the customer component. (Tr. at 96-103). With regard to equity return, the AG recommends that the Commission place little reliance on AWG's risk premium method. (Tr. at 58) The AG also rebuts AWG's conclusions regarding the return on equity based upon the Capital Asset Pricing Model ("CAPM"), recommending that the Commission reject AWG's proposed equity return as too high. (Tr. at 65-67)

NWAGC recommends that the Commission reject AWG's proposed cost of service and its proposed rate design and adopt its proposed methods for allocation. NWAGC recommends greater demand based allocation for production (Tr. at 1098-1101) and transmission (TR. at 1102-1103) functions, greater assignment of cost to the customer component for distribution mains (Tr. at 1118), allocation of storage costs based upon 'heat sensitive' usage (Tr. at 1096), and zero assignment of certain distribution expenses to larger customers. (Tr. at 1097) In addition, NWAGC recommends approval of an equity return derived from application of the DCF as adjusted for flotation cost (Tr. at 1046) and rejection of AWG's application of the CAPM model. (Tr. at 1059) NWAGC also recommends disapproval of AWG's proposed REP. (Tr. at 1097)

The CEUG filed revenue requirement recommendations which relate only to capital structure and equity return and a few specific expense items (Tr. at 1135-1136, 1157-1162, 1182-1184) The CEUG addresses both the cost of service and rate design (Tr. at 1184-1186, 1215) and

proposes (1) more reliance on coincident peak demand after curtailment for cost allocation, (2) implementation of a line item on bills for Lost and Unaccounted For Gas ("LUFG"), with increased allocation on demand and transportation customers allowed to use 'in-kind' payment, (3) cost of gas clause recovery of production/gathering costs and storage costs, and (4) a mechanism for allocation of mains using actual pipe size under the minimum size method. (Tr. at 1186-1208) The CEUG also makes certain proposals regarding tariff provisions for transportation, master metering and billing, weather normalization, and recommends that the Commission approve the REP subject to certain requirements. (Tr. at 1223-1224, 1232-1333)

CONTESTED ISSUES

The Parties have provided an Issues List which contains items still contested by two or more parties. More importantly, the Issues List also provides a list of issues and agreements regarding the disposal of certain previously contested items which we accept and incorporate by reference in this Order. The issues which remain to be decided fall into the following broad areas related to AWG's request in this docket: revenue requirement determination; allocation of revenue requirement to rate class or cost of service; design of resulting rates; tariff provisions; new services; and, certain miscellaneous items. Additionally, AWG's alternative rate change process under its proposed REP remains contested. The Commission addresses below those contested issues identified by the Parties in the Issues List within these general categories.

Revenue Requirement

Issues remaining in dispute which impact the calculation of revenue requirement fall under the general categories of rate base, rate of return, operating expenses, and other revenues. Those

components of revenue requirement determination that continue to be at issue in the rate base category are: *working capital assets* - Cash Balances. Issues still contested related to rate of return used to calculate revenue requirement are: *capital structure; cost of debt – short- term; cost of debt - long-term*; *level of Current, Accrued, and Other Liabilities ("CAOL")*; and *cost of equity.* Those operating expenses used to calculate revenue requirement and which are still in dispute are: *advertising, dues and fees; payroll and payroll taxes - incentive bonuses;* related *fringe benefits; uncollectible accounts expense; officers and directors insurance;* and, the *revenue conversion factor.* Other issues still in dispute which may impact operating expenses are *inter-jurisdictional allocations of cost.*

Rate Base

The appropriate level of cash to be allowed in cash working capital is the only rate base item which remains in dispute. Staff witness Larry Walker, consistent with the last AWG rate filing, Docket No. 02-227-U, has reduced cash working capital by $587,697 to reflect the minimum bank balances required. (Tr. at 1335-1356) AWG witness Morgan seeks approval of an amount equal to a full day's deposit of customer payments, on the basis that these deposits cannot be transferred under bank requirements before one full business day has passed. (Tr. at 327-328) According to AWG witness Morgan, it is only on the second day after deposit that AWG can transfer those funds to SWN to reduce its indebtedness and reduce its interest expense. (Tr. at 327-328) It is therefore appropriate, according to Mr. Morgan, that the full amount of deposits which cannot be transferred from the bank be included for purposes of Cash Working Capital. Should the Commission determine that these balances are not appropriately included as cash, then alternatively, Mr. Morgan

contends that the funds be considered as accounts receivable, reflecting the one day lag between deposit and investment. (Tr. at 328) Staff witness Walker testifies that, while the Commission has determined that the level of cash included in Working Capital Assets should be the minimum amount needed to meet daily operational needs, the Commission also found "'that a portion of the minimum balance could be placed in an interest bearing account . . .,'" which is not included in rate base to earn a return. (Tr. at 1369-1370) In this regard, Mr. Walker also testifies that Mr. Morgan's assertion that $595,297 is the minimum required by the bank is unsubstantiated. (Tr. at 1370) Mr. Walker states that it is not evident that this full $595,000, which is simply the 13-month end average of the account, represents one day's receipts. Furthermore, although Mr. Walker requested an analysis by AWG which would show an average of one day's receipts, no such analysis was provided. (Tr. at 1370) Mr. Walker also testifies that prudent cash management would dictate transferring all funds in excess of minimum bank balances and investing that excess so that it may earn interest, which eliminates the excess from earning a return in rate base. (Tr. at 1371) Mr. Walker testifies that Mr. Morgan's proposed alternative accounts receivable treatment for this excess cash is also not appropriate, as the funds are no longer accounts receivable once they have been received. (Tr. at 1371)

The Commission finds Staff's adjustment appropriate. AWG fails to provide any analysis which indicates its actual minimum operational cash needs nor has AWG provided material evidence to indicate that the 13-month end average represents the average daily receipt of payments. And, as Mr. Walker notes, funds in excess of minimum balances should prudently be moved to available, interest bearing investments. To the extent AWG asks that the Commission allow

alternative treatment as accounts receivable, AWG has failed to establish that recognition as an accounts receivable on a stand alone basis is appropriate under the MBSA or that the actual daily balance of accounts receivable would be materially changed. The Commission, therefore, rejects AWG's cash balance treatment as well as its alternative accounts receivable treatment and approves the adjustment as proposed by Staff.

Rate of Return

Issues remaining in dispute with regard to the calculation of the rate of return for revenue requirement determination are: *capital structure*, *cost of short-term debt*, *cost of long-term debt*, *level of current, accrued, and other liabilities ("CAOL")* and the *cost of equity*. Capital Structure proposals differ only as to the position of CEUG which opposes the position taken by AWG, Staff, and the AG. Additionally, while the majority of the parties have agreed on the overall capital structure with regard to the appropriate level of debt to equity components of 54% debt and 46% equity (Tr. at 55, 647, 941), issues related to the level of and the accounts which should be appropriately included will have an impact on the capital structure and related overall return. Debt cost, both short-term and long-term, are addressed by AWG, Staff, and CEUG witnesses. CAOL levels are addressed by AWG, Staff, and CEUG. Recommendations regarding the appropriate common equity rate are addressed by witnesses for all parties including AWG, Staff, the AG, the CEUG, and the NWAGC.

A. Capital Structure/Debt to Equity Ratio

Staff witness Brown testifies that, because AWG is not a publicly traded company, it is necessary to impute the debt to equity ratio to be included in the capital structure. (Tr. at 646) Mr.

Brown recommends a debt to equity ratio of 54% debt and 46% equity, imputing this ratio using analysis of the debt to equity ratios of a risk-comparable sample of companies having similar characteristics of AWG. Mr. Brown also notes that he has checked his imputed debt ratio of 54% against the current Standard and Poors ("S&P") published financial benchmarks, given AWG's expected credit rating and business risk profile, and determined that his recommended debt percentage fell within the S&P benchmarks. (Tr. at 638-642, 646-647) CEUG witness Tinsley recommends that the Commission maintain the capital structure approved in AWG's last rate case in Docket 02-227-U, with 52% debt and 48% equity, a recommendation which AWG witness Gunter states the Company will not oppose. (Tr. at 941-942, 1158-1160, 1270) Mr. Tinsley agrees with Staff that an imputed capital structure may be appropriate but disagrees with Staff's proposal, testifying that review of Mr. Brown's sample indicates he has included two companies with "highly irregular" levels of debt. Mr. Tinsley notes that, if these companies are removed from the sample, the resulting debt ratio would be approximately 52%. Mr. Tinsley also recommends that the Commission consider providing general guidance to parties in setting capital structures that will result in the lowest cost, without financially jeopardizing the company. Mr. Tinsley asserts that the current process is too cumbersome and that reliance on comparisons to other regulated utilities may not provide the correct result, relegating it to the decisions of other regulators. (Tr. at 1268-1270)

AWG is not a publicly traded company and the Commission finds that using the sample average of publicly traded companies is a reasonable method to develop a proxy. Staff conducted a full analysis of companies to produce a risk-comparable sample of other gas utilities. The Commission also finds that, alternatively, Mr. Tinsley has done no independent sample analysis.

Mr. Tinsley recommends exclusion of two companies from the Staff sample based solely on debt levels he deems "highly irregular." The Commission, however, finds that exclusion of these companies as "outliers" ignores the basis of using a sample average which will appropriately catch the vagaries of companies with similar business risks and similar operations. The Commission also finds Mr. Brown has appropriately tested his results based on external benchmarks and that those benchmarks support his results and recommendation. The Commission rejects Mr. Tinsley's proposal and adopts for revenue requirement calculation, the capital structure proposed by Staff.

B. Cost of Debt - Short Term

AWG witness Gunter testifies that neither AWG nor SWN recognizes short-term debt as a capital source in each company's respective capital structure. He also states that he accepts Staff's recommendation to impute 8.12% of external capital as short-term debt. Mr. Gunter, however, also testifies that the Commission should adopt a cost rate for that imputed debt of 4.49% which is applicable to SWN's multi-year revolver account, an account with properties similar to short-term debt, and that the Commission rejects Staff's proposed rate of 2.14%, which is the average short-term debt rate of Staff's proxy group. (Tr. at 938-939) Staff witness Brown recommends that the Commission adopt the end of period 2004 average rate paid by the risk-comparable sample of utilities, which would provide for a cost for short-term debt of 2.14%. Mr. Brown testifies that adopting the sample's rate provides an accurate and up to date cost of short-term debt consistent with his overall methodology in assessing the reasonableness of the capital structure components and each component's cost. (Tr. at 651) Mr. Brown rejects Mr. Gunter's proposed use of AWG's parent debt to set a cost of debt, testifying that AWG has already accepted Mr. Brown's sample

average debt proportion and it is more appropriate to reflect the average debt cost of those sample companies than it is to reflect debt cost of AWG's more risky parent. (Tr. at 678-679) Mr. Brown also testifies that he has, however, updated that cost to reflect more current interest rates, and recommends a cost of short-term debt of 3.94%. (Tr. at 679)

The Commission finds that Mr. Brown's methodology represents a consistently applied one, which, in effecting a hypothetical capital structure and its component costs, coordinates the relationship among capital structure components with the rate applicable to each component. Mr. Gunter adopts Staff's proposed external capital structure which, as Mr. Brown testifies, is based upon that of comparable utilities. However, Mr. Gunter fails to price those components consistent with those same utilities, rather adopting internal costs on a piecemeal basis. The Commission finds AWG's proposed method less consistent and reasonable than that applied by Staff and, therefore, adopts the level of and cost for short-term debt which Mr. Brown proposes.

C. Cost of Debt - Long Term

AWG witness Gunter proposes that the cost of long-term debt should be the weighted average cost of long-term debt for SWN, as adjusted to recognize the losses on reacquired debt. (Tr. at 892) AWG proposes a rate of 8.401% as updated in Mr. Gunter's Rebuttal Testimony. That, he testifies, is the current June 30, 2005, long term-debt rate of 7.972%, adjusted for reacquired debt losses and excluding SWN's revolver capital source ("Revolver"). It is Mr. Gunter's position that Staff has inappropriately included the Revolver as part of long-term debt, when it actually reflects a short-term source with a lower cost. Mr. Gunter testifies that by including a short-term debt source,

the Revolver account, as long-term debt, Mr. Brown essentially exceeds his proposed hypothetical level of short-term debt. (Tr. at 939-940. Ex. at 1553)

Staff witness Brown testifies that he also uses SWN's most current cost of debt of 6.571% as a proxy for that of AWG and, as adjusted for unamortized discounts and expenses, is 7.047%. (Tr. at 651) Mr. Brown testifies that he accepted this cost of debt specifically because it fell within the range of the weighted average cost of long-term debt for his sample companies. That range, he testifies, is between 4.92% and 7.73%, with an average of all companies of 6.54%. He notes that Mr. Gunter's proposed rate of 8.401% not only is greater than the average but falls outside of the entire range. Mr. Brown continues to recommend his original cost of long-term debt, 7.047%, be used on calculation of revenue requirement. (Tr. at 680)

CEUG witness Tinsley testifies that combining an imputed capital structure, which reflects less equity than the actual, with an imputed cost of debt, which reflects a lower cost than the actual, is unduly punitive to AWG. Mr. Tinsley testifies that he analyzed the sample companies used by Mr. Brown and noted that for these companies, as the level of equity increases, the cost of debt decreases. Mr. Tinsley concludes that Mr. Brown's use of the actual cost of debt, which is a result of AWG's higher equity level, coupled with an imputed and lower equity level, rewards ratepayers with a lower debt cost than would be achieved under the lower equity level. Mr. Tinsley recommends that the cost of debt be adjusted by adding 7.08 basis points to the actual cost proposed by Mr. Brown to reflect the debt cost which would be effected for a company with reduced equity. (Tr. at 1270-1272) We agree with Mr. Tinsley's 7.08 basis points adjustment.

The Commission finds that Mr. Brown's proposed cost for long-term debt falls within the

range of long-term debt cost of the sample companies he uses to test the reasonableness of AWG's requested capital costs. The Commission notes that Mr. Brown's rate is in the upper range of those sample companies and, in fact, exceeds the average of the sample. The Commission also finds that Mr. Gunter's proposed rate also exceeds the average of the sample but his proposed rate also exceeds the uppermost debt cost of that sample by a significant level and, as such, does not reflect a reasonable cost rate. Therefore, with the exception of Mr. Tinsley's 7.08 basis points adjustment, we find that Mr. Brown's methodology and proposed long-term debt cost is reasonable and supported by substantial evidence. The Commission, therefore, adopts a long-term cost of debt of 7.1178%, adding 7.08 basis points to Staff's proposed rate of 7.047%.

D. Level of Current, Accrued, and Other Liabilities or CAOL

AWG has included in its application a calculation of its working capital needs using the Modified Balance Sheet Approach ("MBSA"), pursuant to Commission Order No. 7 in Docket No. 84-199-U. (Tr. at 1354-1335) AWG witness Gunter testifies to and sponsors Schedule D-6 of AWG's Application containing the summary of Current, Accrued, and Other Liabilities ("CAOL"), with adjustments, which AWG has included in its capital structure at zero cost. (Tr. at 893) Staff witness Walker supports and testifies to Staff's calculation in this regard and the differences between the AWG proposed CAOL level and that proposed by Staff. Mr. Walker testifies that Staff has included $22,228,055 in CAOL (Tr. at 1373) whereas Mr. Gunter includes $16,821,321 in CAOL. (Tr. at 934)

Both Mr. Gunter and Mr. Walker have adjusted the CAOL to 13-month end balances, which should be more representative of their average balance, and removed interest bearing accounts,

which are included elsewhere in the capital structure. (Tr. at 894, 1357-1358) However, Mr. Gunter objects to the inclusion in CAOL of (1) certain other deferred credits in the amount of $65,733 and (2) deferred gas purchase costs related to unbilled revenues in the amount of $5,341,001. (Tr. at 928) Mr. Gunter testifies that the deferred credits account to which he objects relates to the estimate of certain FERC revenues and are "trued-up" each year. This account can be either a debit or credit from one year to the next and that, because it is such a "quick turn around," item it is not appropriate for long-term ratemaking. (Tr. at 933-934)

Mr. Gunter also testifies that, while both AWG and Staff do not include the over/under account for gas cost on the asset side, Staff has included in CAOL the deferred gas purchase cost account which is created when booking unbilled revenues. Mr. Gunter testifies that, when including this account on the liability side of the MBSA, there is no appropriate matching asset booked to rate base. Mr. Gunter asserts that the lack of an offsetting asset entry and the volatile nature of the liability render this account inappropriate for inclusion as a zero cost item for long-term ratemaking. (Tr. at 932-933)

Mr. Gunter also testifies that, although the MBSA approach to measuring working capital is supposed to mimic the results of conducting a lead-lag study, he questions whether the two methods will produce the same results with regard to gas cost items. (Tr. at 935-936) He observes that the gas cost portion of accounts receivable (the gas cost included in the revenue which produced the account receivable) may be either more or less than the gas cost which is payable. Under the MBSA, he notes, this will result in either a positive or negative working capital requirement, while

most utilities will pay for gas consumed before recovering it from ratepayers. Under the lead-lag method, working capital requirement will almost always be positive. (Tr. at 936)

Staff witness Walker, as supported by CEUG witness Tinsley, makes no changes to his originally filed CAOL levels. (Tr. at 1274-1275, 1373) Mr. Walker rebuts both Mr. Gunter's proposed exclusions from the CAOL and his observations regarding lead-lag results in comparison to the MBSA results in measuring working capital. With regard to the latter, Mr. Walker testifies (1) Mr. Gunter does not provide a lead lag study to which he can compare MBSA results, basing his observations on only one liability account and a part of one asset account (Tr. at 1364-1365); (2) the only way to compare the two is to compare their net revenue requirement impacts - piecemeal comparisons of only portions of the components included in the MBSA or lead-lag are not valid (Tr. at 1365); and (3) the Commission's application of the less complicated and less expensive MBSA as an alternative for lead lag studies has, for the last 20 years, been upheld on appeal. (Tr. at 1366-1367) Further, Mr. Walker testifies there is no flaw in the MBSA because of the different working capital treatment of the over/under gas cost account and the deferred over/under account, testifying that one account accrues interest (to be received or to be paid depending on whether it is positive or negative) and is excluded from working capital treatment, while the deferred account does not accrue interest and is included. (Tr. at 1367)

Mr. Walker also explains that including the deferred gas account in liabilities without a corresponding asset in rate base is appropriate and that assets and liabilities need not be equal. (Tr. at 1368) He also testifies that the volatility of both liability accounts at issue is no reason to exclude

them from working capital treatment, noting that many accounts are seasonal and volatile, which is why a 13-month average is used to measure them. (Tr. at 1369)

With one exception, the Commission finds that Mr. Walker has appropriately included all non-interest bearing liabilities, using 13-month end averages, in CAOL as contemplated by the MBSA. However, we agree with AWG witness Gunter that the deferred gas purchase costs of $5,341,001 related to unbilled revenues should not be included in CAOL.

E. Cost of Equity

AWG, Staff, the AG, NWAGC, and CEUG each offer cost of equity testimony and each propose a different rate. AWG witness Morin's final recommendation is that AWG be allowed a cost of equity of 11% (Tr. at 540), Staff witness Brown recommends an equity return of 9.7% based upon a range of reasonableness of 9.2% to 10.1% (Tr. at 673, 677), AG witness Marcus recommends an equity return of 9.5% (Tr. at 124), NWAGC witness Cassidy recommends an equity return of 9.24% (Tr. at 1044), and CEUG witness Tinsley originally recommended that the Commission approve an equity return based on AWG's last approved rate case or a maximum return of 9.9%.[5] (Tr. at 1162)

1. <u>AWG Recommended Return on Equity</u>:

AWG witness Morin bases his recommended equity return of 11.0% on analysis he performs using the Capital Asset Pricing Model ("CAPM") and the Risk Premium ("RP") method, which are both risk premium approaches, and the Discounted Cash Flow ("DCF")

[5] In Surrebuttal Testimony, Mr. Tinsley does not specifically recommend the same return, but rather recommends that the Commission set a return on equity "that is appropriate for the current LDC business environment with due consideration of flotation costs and all available methods of analysis including DCF, CAPM, and RPM." (Tr. at 1278)

method. Dr. Morin testifies that he ran (1) one normal CAPM and an empirical approximation of the CAPM ("ECAPM"), (2) three RP models, including an analysis based on natural gas distribution companies' historical data, one based on electric utilities' historical data as a proxy for AWG's energy business, and one using risk premiums allowed by regulators in setting rates for natural gas distribution companies. (Tr. at 391)

According to Dr. Morin, the basis for using risk premium methods is to set equity based upon a risk-free rate and add to it the premium required by investors for bearing incremental risk. (Tr. at 407) Dr. Morin testifies that it is necessary to evaluate the results of varied methods, applied to varied companies to avoid errors, omissions, and to accommodate vagaries in the market data. Further, he notes that reliance solely on DCF, as some commissions do, ignores capital market evidence. (Tr. at 399-401, 403, 404, 406) Dr. Morin testifies that, using CAPM and ECAPM analysis, his equity returns with flotation costs[6] range from 11.8% to 12.7%, with a 12.3% average. (Tr. at 418) He testifies the results of his RP analysis for gas distribution companies, for electric distribution companies, and for the one using the regulator-allowed risk premiums, including flotation costs, range from 11.0% to 11.8% and average 11.4%. (Tr. at 418-425) Dr. Morin also testifies that, using the DCF model and the proxy samples of both gas distribution companies and combination gas and electric distribution companies, his range of equity returns, with

[6] Flotation costs are direct and indirect, or market pressure, costs which are incurred upon issuance of stock and Dr. Morin testifies he has incorporated the impact of these costs as a percent of the dividend yield in calculating his expected equity return. (Tr. at 431 - 435)

flotation costs, is 9.3% to 10.4%. (Tr. at 424-431) Dr. Morin asserts that AWG faces demand and financial risks greater than other gas distribution companies and, therefore, experiences greater investment risk than other gas distribution companies. For these reasons, Dr. Morin concludes that AWG requires an additional equity return of 30 basis points to recognize that increased risk. (Tr. at 436-441) Dr. Morin recommends, based upon current market conditions and his judgment, an equity return of 11.0% for AWG, which is lower than his initial recommendation of 11.5%. (Tr. at 540)

2. Staff Recommended Return on Equity:

Mr. Brown testifies that he has applied the DCF method to his sample using the appropriate price term, dividend term, and growth rates which results in a range of reasonable returns for AWG of 9.2% to 10.1% within which his recommend equity return of 9.7% falls. (Tr. at 655-658) In addition, he testifies that, as a check, he has run a comparable analysis which confirmed the reasonableness of his DCF results. (Tr. at 658-660) Mr. Brown also testifies that, as a check to Morin's 30 basis point flotation cost adjustment, he has calculated an estimate of actual flotation costs as a percent of stock and concludes that it would be less than 5 basis point. He concludes that, therefore, no such adjustment is appropriate. (Tr. at 669-672) Mr. Brown recommends that the Commission adopt his DCF analysis and return on equity.

3. AG Recommended Return on Equity:

AG witness Marcus recommends an equity return of 9.5%. (Tr. at 124) In support of his proposed return, Mr. Marcus also recommends that (1) the Commission focus its

attention upon the opinion of utilities and market analysts, when they are not testifying in support of rate increases (Tr. at 60-62), and (2) the Commission also focus on current market-to-book ratios for gas utilities. (Tr. at 64-65) In this regard, Mr. Marcus testifies that, based on SWN's own annual report disclosures regarding its employee pension investments and based on his sample of gas utilities' pension fund investments, expected returns for these funds approximate an average of 9% and between 8% to 9%, respectively. (Tr. at 61-64) He also testifies that current comparison gas utilities' market-to-book ratios are approaching 185%, which indicates that investors see gas utility returns as providing significantly healthy earnings relative to original cost. (Tr. at 64-65) Mr. Marcus asserts that, with the overall market expecting returns of 10-11%, equity returns for the less risky utility should be much less. He testifies that he has run his own CAPM analysis reflecting the expectations of pension fund managers. He notes that the analysis indicates expected returns of 8.5% to 9.9%, a range he also recommends can be used to measure the reasonableness of DCF results. (Tr. at 65-67)

4. **NWAGC Recommended Return on Equity**:

NWAGC witness Cassidy recommends, based solely upon his DCF analysis, a return on equity for AWG of 9.24%. (Tr. at 1044, 1046-1047) Mr. Cassidy testifies that he adopted, with one exception, Dr. Morin's proxy group (Tr. at 1046-1047), and he ran the DCF under three different growth rate assumptions.[7] (Tr. at 1048-1052) He notes that,

[7]The growth rate assumptions used by Mr. Cassidy are: DCF with short term, using the mean of the 5-year growth rates taken from Zacks Investment Research, April 5, 2005 (Tr. at 1053, Ex. at 1577), DCF with a two stage growth rate, using the short term above and the sustainable growth rate (Tr. at 1054-1055, Ex. at 1583), and DCF with a three stage

applying a quarterly dividend payment schedule which reflects SWN's actual dividend payment schedule (Tr. at 1053), his analysis results, under the three assumptions were (1) from 7.93% and 10.12%, averaging 9.06% (Ex. at 1578), (2) from 7.39% to 11.01%, averaging 8.53% (Ex. at 1585), and (3) from 7.93% to 10.25% averaging 8.79% (Ex. at 1589). Averaging the results of his three different models, Mr. Cassidy recommends that the appropriate equity return for AWG should be 9.0%. (Tr. at 1056-1057) Mr. Cassidy testifies that he also has calculated flotation costs for AWG in the amount of .24% which he has added to his return and recommends an overall equity return of 9.24%. (Tr. at 1057-1058)

5. CEUG Recommended Return On Equity:

CEUG witness Tinsley originally recommended that the Commission adopt the maximum equity return approved in AWG's last rate case in the amount of 9.9%, asserting that AWG has not sufficiently justified its requested return on equity. (Tr. at 1162) However, in Rebuttal, Mr. Tinsley recommends only that the Commission set equity return, fully considering all forms of analysis, the current gas utility business environment, and any flotation costs applicable. He also recommends that the Commission adjust that return appropriately if the Commission approves the WNA or REP. Mr. Tinsley also recommends that "(t)he Commission should consider providing guidance to the parties on the subject of the ROE in an effort to streamline the ratemaking process." (Tr. at 1278-1279)

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growth rate, using the short term above, the sustainable as discussed, and the long term growth rate for GDP. (Tr. at 1055-1056, Ex. 1589)

6. Return on Equity - Response to AWG Filed/Rebuttal/Surrebuttal

Staff witness Brown testifies that Dr. Morin's proposed equity return is unrealistic and contrary to movement in the capital markets where interest rates are falling. (Tr. at 663) Mr. Brown testifies that he also used a proxy sample of companies which will be used to effect an appropriate cost of capital for AWG, a non-publicly traded company, but notes that Dr. Morin's sample appears to be riskier than AWG, thus, resulting in higher equity estimates. (Tr. at 639-642) He rebuts the weight Morin has assigned to methods other than DCF in estimating a fair equity return, noting that the risk premium methods are not industry or company specific and that the CAPM approach incorporates assumptions, as do all financial models, for which financial analysts must accommodate in estimating expected equity returns. Mr. Brown also notes that the Commission has consistently and repeatedly expressed its preference for application of the DCF model. (Tr. at 664-666) Mr. Brown observes that use of risk premia exposes RP analysis to fluctuating and unstable results, noting that Morin's RP risk premia values for his natural gas sample ranged from -27.89 % to 61.21%, an over 8900 basis point spread, with risk premia from his electric sample ranging from -37.34% to 71.96%, a basis point spread of over 10,900, and that significant reliance on this method will reflect that instability of results. (Tr. at 666-667) In addition, Mr. Brown criticizes Dr. Morin's application of the CAPM which he states is a form of RP and, as such, is subject to all the same infirmities. Mr. Brown testifies that, in Dr. Morin's application of CAPM, Dr. Morin assumes earnings growth of 16.4%, a level which is not commensurate with investors' and analysts' market expectations. (Tr. at 667-668)

AG witness Marcus testifies that (1) some of the companies in Dr. Morin's sample include regulated gas distribution companies engaging in other activities and that those companies should be eliminated (Tr. at 55-56), (2) the RP method is circular, one in which commissions are basing equity returns on the possibly generous equity returns already provided by other commissions[8] (Tr. at 56-59), (3) Dr. Morin's CAPM model uses stock and income growth rates of 13.5% and 16.7%, respectively, which Dr. Morin fails to support and which are not credible (Tr. at 58-60), and (4) Dr. Morin's analysis is not particularly well supported given that his application of the CAPM depends, in large part, on estimates previously made by analysts for 1983-1998. (Tr. at 60, footnote omitted)

In addition, Mr. Marcus recommends that the Commission consider the reduced risk and increased earned returns of gas utilities as a whole and, when doing so, weigh the reasonableness of Dr. Morin's resulting equity return of 10% to 11%. Mr. Marcus additionally notes that using the CAPM model will actually produce returns ranging from 8.5% to 9.9%, if more reasonable assumptions[9] are adopted. (Tr. at 65-66)

NWAGC witness Cassidy testifies that Dr. Morin has erred in his analysis, resulting in an overstatement of required equity return. (Tr. at 1059) Mr. Cassidy testifies that those errors include (1) Dr. Morin's choice of methods, including the CAPM and RP, as well as

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[8]Mr. Marcus notes that risk premiums for gas utilities have actually been declining, with Dr. Morin reaching back to pre-1960 to effect his estimate of the risk premium. Using only the last 19 years, the risk premium has been only 3.46%. Further, he notes that gas utilities, a lower risk investment, are actually earning returns reflective of the market for more risky and non-regulated entities, indicating the circularity of the RP model and the expected willingness of investors to continue to invest in gas utilities, even with lower equity returns approved by regulatory bodies. (Tr. at 57-58)

[9]Mr. Marcus suggest that those more reasonable assumptions would be those made currently by corporate actuaries.(Tr. 65-66)

the data he used under those methods and under the DCF, (2) his adjustments for Flotation Costs, and (3) his adjustment to reflect the increased risk he asserts AWG faces.

With regard to Dr. Morin's choice of methods, Mr. Cassidy testifies that Dr. Morin has inappropriately relied on the CAPM model which, by its very theory[10], assumes a diversified portfolio rather than one which reflects comparable risk. Mr. Cassidy explains that the Bluefield[11] decision requires that equity returns reflect only companies of comparable risk. Mr. Cassidy concludes that, given the CAPM model always assumes a diversified portfolio, it should not be used for equity determination. (Tr. at 1059-1061) Mr. Cassidy testifies that, even if the Commission wishes to consider the CAPM as corroborative evidence, Dr. Morin's execution contains several flaws, including his use of an incorrect risk-free rate, his failure to use the true risk-free proxy which is the 3-month Treasury bill, and his failure to justify the use of the ECAPM. (Tr. at 1061-1063) Mr. Cassidy testifies further that, although the CAPM would yield an equity return of 10% if these errors were corrected, it is his opinion that the CAPM analysis is not a valid indicator of the required equity return for AWG. (Tr. at 1064-1066) Mr. Cassidy also testifies that Dr. Morin's reliance on the historical RP method is suspect as it is based upon a proposition[12] that is

[10]Mr. Cassidy testifies that "(p)roponents of the CAPM believe that the amount of company specific risk in a portfolio can be reduced to zero through diversification, leaving the portfolio exposed only to market risk...(t)herefore, the CAPM is valid only when applied to a diversified portfolio." (Tr. at 1059-1060)

[11] Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

[12]Mr. Cassidy states that Dr. Morin's historical risk premium analysis assumes that investors base their current risk premium on the average of historical results, but it is also generally accepted that an investor's actual return or realized return, when he sells his investment, is rarely the same as the return he expected, or the required return, at the time he purchased that investment. (Tr. 1065-1066)

impossible to prove or disprove. Further, he notes, that should the Commission give consideration to the RP, it is more appropriate to use current bond yields rather than "expected" bond yields, given the unreliability of those "expected" yields. (Tr. at 1066-1067) Third, Mr. Cassidy testifies that Dr. Morin's DCF model inappropriately relies completely on certain short-term growth rates, which are not representative of the market consensus. (Tr. at 1067-1068) Fourth, Mr. Cassidy testifies that he supports recovery of flotation costs as costs appropriately used to measure required returns, but, that those costs are only related to issuance of new stock. Absent that proof of a new issuance, the cost should not be included. (Tr. at 1068-1069) Finally, Mr. Cassidy testifies that he disagrees with Dr. Morin's contention that a premium should be included to recognize that, as a smaller company, AWG is a riskier investment than other distribution companies. Mr. Cassidy testifies that AWG resembles a large, less risky company and therefore no 'premium' is needed. (Tr. at 1070-1071)

Dr. Morin criticizes Staff's equity calculation (1) for its reliance on the single DCF method, which he contends understates equity returns because it fails to adjust for any book to market difference in the price of stock (Tr. at 479-484), (2) for Mr. Brown's use of understated dividend yields (Tr. at 484-488), (3) for his mismatch of stock price and growth (Tr. at 489), (4) for Mr. Brown's use of stale data (Tr. at 489), (5) for his failure to reflect, in his risk premium check, the inverse relation of interest to risk premium (Tr. at 496-497), and (6) for his failure to include flotation costs (Tr. at 490-492).

Dr. Morin also defends his analysis against certain of the criticisms of AG witness

Marcus, noting that, use of historical market risk premiums ("MRP") to determine expected MRP is well supported by current financial literature, common practice, and by review of the implicit return on equity allowed by regulators. (Tr. at 513-515) Dr. Morin also disputes Mr. Marcus' contention that use of RP is circular. Dr. Morin testifies that neither the risk-free rate nor the beta risk measure, required components of the RP method, are subject to regulatory determination but are, rather, market driven and set by supply and demand. Dr. Morin continues that it is actually the DCF model which suffers from circularity, given the expected growth rates applied are, by and large, determined by regulatory treatment. (Tr. at 516) Dr. Morin also rebuts the AG's recommendation that the Commission consider the current higher gas utility realized earnings returns when setting a utility's required return, noting that Mr. Marcus relies too heavily on short term market information rather than periods which are long enough to smooth out aberrations and encompass several business and interest cycles. (Tr. at 517-518) And, finally, dismissing the AG's observation that, given lower tax rates, required returns would also be less, Dr. Morin notes that not all investors are taxable. (Tr. at 518)

Dr. Morin also dismisses Mr. Marcus' analysis and recommended equity return, stating that Mr. Marcus conducted very little independent analysis, did not develop any of his own comparable company samples, performed no independent RP analysis, and provided a CAPM analysis in which he has used inappropriate inputs. (Tr. at 508-510) Further, Dr. Morin questions whether pension fund data assumptions, extracted from only specific companies, are appropriate to use in determining market risk premium. (Tr. at 510)

Dr. Morin also defends his use of the CAPM and Historical Risk Premium against Mr. Cassidy's criticism. (Tr. at 528-529, 533-536) Dr. Morin criticizes Mr. Cassidy for using only the DCF method in arriving at an equity return recommendation and for the limited scope of Mr. Cassidy's analysis which, he notes, is based on Dr. Morin's evaluation, not Cassidy's. (Tr. at 519, 480-522) Dr. Morin also criticizes Mr. Cassidy's application of the sustainable growth assumption in two of the three DCF models run by Mr. Cassidy. Dr. Morin asserts that (1) Mr. Cassidy's growth assumption does not consider external stock financing, (2) Mr. Cassidy's growth rates applied to the sample companies reflect higher equity returns than Mr. Cassidy recommends, (3) his method is not supported by financial literature, (4) Mr. Cassidy relies too much on Value Line for the analysis, and, (5) Mr. Cassidy's expected return is based on end of period book equity rather than the average. (Tr. at 523-528)

In surrebuttal, Staff witness Brown continues to support DCF as the preferred approach to measuring required equity return. And, despite Dr. Morin's contention that he did otherwise, Mr. Brown states that he also conducted multiple analysis using other methods to test for reasonableness. He asserts that the results of those differing methods served as a reasonableness check against the DCF method and appropriately reflected, as Dr. Morin's analysis did not, similar levels of equity return. Witness Brown testifies that, had Dr. Morin applied more reasonable and less flawed inputs into his models, his results would have also reflected equity ranges which were similar across all methods. (Tr. at 684-685) Noting Dr. Morin's recommendation to consider the market to book ratio for return

measurement, Mr. Brown states that Dr. Morin inappropriately faults Staff for not doing so in its analysis. (Tr. at 685-686) Witness Brown contests Dr. Morin's assertion that the DCF model understates equity return requirements, pointing out that the DCF is the most widely accepted method used by commissions. Mr. Brown states that if Dr. Morin's contentions were true, and given its acceptance and widespread application, utilities would have over the years had significant difficulty in attracting capital. That has not occurred and, in fact, utility external capital has increased significantly. (Tr. at 686) Mr. Brown testifies that Dr. Morin is also mistaken that use of a quarterly, rather than an annual, dividend payment schedule understates dividend yield and, therefore, understates the resulting return. The dividends are paid quarterly and the model Mr. Brown uses, therefore, appropriately captures the time value to investors of that payment schedule. (Tr. at 687) Mr. Brown also contests Dr. Morin's inference that Staff inappropriately used non-current or 'old' stock prices and that the prices used were not from the time period from which growth rates were taken. Mr. Brown testifies, first, that he appropriately used a 13-week average[13] in contrast to Dr. Morin's use of only current prices and, second, that the growth information corresponded directly with the first week included in that average. (Tr. at 687-688) Mr. Brown testifies that he continues to recommend disallowance of both Dr. Morin's flotation cost adjustment and risk adjustment. Mr. Brown testifies that Dr. Morin's flotation cost request includes, not only costs related to expected future issuances of stock, but also all cumulative past,

[13]Mr. Brown testifies that the 13-week average should be used to "eliminate the influence of random stock market fluctuations . . . , " in which stock prices can vary widely, given utility rates are set to be in effect for a much longer period of time. (Tr. at 688)

unrecovered amounts. Mr. Brown testifies further that Dr. Morin provides no new evidence to support his contention that investment in AWG represents a higher relative risk than the sample average. (Tr. at 690, 692)

AG witness Marcus testifies that Dr. Morin has failed to address or provide support for his excessive estimates for stock or income growth at 13.5% and 16.7%, respectively. (Tr. at 121) Mr. Marcus defends his own analysis against Dr. Morin's criticism regarding the AG's use and source of the actuarial data. Mr. Marcus testifies that his analysis provides an appropriate perspective of a large group of equity market investors who, as utility pension fund investors, are not offering testimony in utility rate-of-return proceedings. (Tr. at 122) Mr. Marcus notes that, in addition, he received his information, not from a 'selective' group of companies, but rather from all Arkansas utilities from which the AG has requested this information and, more importantly, from all companies included in Dr. Morin's sample proxy. (Tr. at 122-123) Mr. Marcus also provides current articles related to expected equity returns which indicate returns will likely be less than 10%. (Tr. at 123, Ex. at 57-67)

NWAGC witness Cassidy defends his use of DCF as the preferred method used in determining his recommended return on equity. Mr. Cassidy rejects Dr. Morin's contention that the DCF method understates the cost of capital and also rejects Dr. Morin's contention that any proposed return on equity is not valid if it is less than the current earnings of the proxy companies used to calculate that equity cost. (Tr. at 1075-1085) Mr. Cassidy continues to recommend the DCF method and defends his criticism of the CAPM and the ECAPM. He reiterates that these methods are applicable only to samples of large,

diversified companies and, therefore, not appropriate for setting regulated rates for which risk-comparable companies must be used. (Tr. at 1075-1085) Mr. Cassidy reiterates his view that the RP, as applied by Dr. Morin, does not appropriately measure the required return on equity. Mr. Cassidy states that, for RP to be applied correctly, Dr. Morin must show that the spread between earned returns on stocks and those on bonds is the same as the spread between the required returns on stocks and those on bonds, which he has not. (Tr. at 1086) Mr. Cassidy defends his acceptance of DCF as the most valid method and rebuts Dr. Morin's criticism that Mr. Cassidy has not given full consideration, in calculating an appropriate equity return, to the earned returns and the book to market ratio of stock. Mr. Cassidy explains that the DCF model, in fact, "provides a logical framework to analyze the cost of capital and the appropriate allowed return on equity. . ." and that its proper implementation will actually push the market value to the book value of stock. (Tr. at 1074-1075) He explains that "(t)he fact that the stock prices are currently in excess of book value simply indicates that the utilities in (the) proxy group. . . are earning returns on book value that exceed the investors' required returns. It is only natural that investors will bid the price of these stocks to a level higher than their respective book values." (Tr. at 1074) Mr. Cassidy provides an illustration of the impact on market price of setting regulated equity at different levels. He explains that:

> . . . the relationship of the earned return and required return and how they affect the price/book ratio show that the expected return used in the growth rate of the DCF model will be equal to the return that investors require for an investment only when the market price and book value are equal . . . that the expected return is different from the required return is not an indication that the DCF model is invalid. It

> merely indicates that the market price and book value are different . . . the return required by investors is the same before and after a rate case that sets a new allowed rate of return. The only change will be the movement of the stock price toward book value.

(Tr. at 1081-1082)

Mr. Cassidy also responds to Dr. Morin's criticism regarding Mr. Cassidy's failure to adjust for growth. Mr. Cassidy testifies that his computation of the effect of new stock sales on growth indicated either very limited or negative growth and, therefore, he continues to recommend no growth adjustment. (Tr. at 1083-1084)

Commission Finding

The Commission finds that AWG's proposed return on equity of 11.0% is excessive. The Commission has reviewed the analysis which AWG proffers as support for its equity return, noting the Company's heavy reliance on the CAPM and RP results, which produce significantly higher returns than the DCF model. (Tr. at 424-431) The Commission has also reviewed AWG's contention that it faces greater risk than other gas distribution companies and, therefore, needs a higher return to reflect that risk - in this case - an additional 30 basis points. (Tr. at 441) Finally, the Commission has reviewed and considered AWG's request for another 30 basis points Dr. Morin recommends as an appropriate flotation cost adjustment. (Tr. at 433-434)

The Commission finds, first, that an appropriately produced DCF analysis provides a more accurate and independently determined required return on equity than does a RP analysis, which may be subject to fluctuating and unstable results as reflected by AWG's own analysis. The Commission notes the width of the risk premia spreads of Dr. Morin's sample companies ranging from negative 27.89% to 61.21% for his gas utility sample and from negative 37.34% to 71.96% for

his electric company sample. The basis point spread of these two sets of results is 8910 (61.21 + 27.89) and 10,930 (71.96 + 37.34) respectively. (Tr. at 666-667) Additionally, the Commission notes the superiority of the DCF method, which uses only data from companies which have the same business and financial risks as the company subject to analysis, while RP bases its analysis on market-wide data, incorporating into that analysis the risk profiles of companies "ranging from gold mining, to farming, to computer technology, to automobile manufacturing." (Tr. at 664) With regard to Dr. Morin's CAPM and ECAPM analyses, which are also variants of the RP methodology and subject to the same limitations, the Commission finds that this analysis is based upon an excessive risk-free rate and excessive earnings growth assumptions which are unsupported and which produce excessive equity return results. (Tr. at 668) Current 30-year U.S. Treasury Bond yields are 4.36%, while the lower end of AWG's proposed risk-free rate range is 4.5%. (Tr. at 685) AWG's analysis also assumes earnings growth of 16.4%, but the record does not reflect an adequate response to questions raised about whether such high estimates are sustainable and the unreasonable results which can be extrapolated if they are adopted. (Tr. at 58-60, 668, 684-685)

The Commission also finds Dr. Morin's criticisms of the DCF method are exaggerated, if not flawed. Dr. Morin contends that the DCF model understates the cost of equity if the market price for stock exceeds its per book cost and, alternatively, the DCF model overstates the cost of equity if the market price of stock is less than per book. (Tr. at 480) Dr. Morin states that this happens because "the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base." (Tr. at 480) It is Dr. Morin's contention that the DCF formula does not properly account for differences in the book-to-

market ratio. (Tr. at 481-483) However, as demonstrated by the evidence before us, "(t)he fact that the stock prices are currently in excess of book value simply indicates that the utilities in (the) proxy group . . . are earning returns on book value that exceed the investors' required returns. It is only natural that investors will bid the price of these stocks to a level higher than their respective book values." (Tr. at 1074-1075) Mr. Cassidy provides an illustration of the impact on market price of setting regulated equity at different levels and explains "the relationship of the earned return and required return and how they affect the price/book ratio show that the expected return used in the growth rate of the DCF model will be equal to the return that investors require for an investment only when the market price and book value are equal . . . that the expected return is different from the required return is not an indication that the DCF model is invalid. It merely indicates that the market price and book value are different . . . [t]he return required by investors is the same before and after a rate case that sets a new allowed rate of return. The only change will be the movement of the stock price toward book value." (Tr. at 1081-1082) The Commission, therefore, finds that Dr. Morin's proposed market adjustment is not required. The Commission sets return based on book value, which represents the actual equity provided to AWG.

The Commission also finds that Staff's DCF model does not, as Dr. Morin claims, understate dividend yields simply because Mr. Brown employed a quarterly DCF calculation rather than an annual one. (Tr. at 484-488) Because such dividends are paid quarterly, it is inappropriate to impute those payments as if paid annually and Staff's choice of model appropriately recognizes the "time value of investors receiving their dividends quarterly. . .." (Tr. at 687) The Commission also finds that Staff has correctly used an average of returns and there is no "mismatch" of Staff's

stock prices with growth data as Dr. Morin asserts. (Tr. at 489-491) Staff witness Brown has appropriately used a 13-week average, which will reduce market fluctuations, and his growth information corresponds directly with the beginning of his 13-week period. (Tr. at 687-688) The Commission also finds that AWG's request for a flotation cost adjustment is excessive and the request for additional return to offset AWG's "higher" risk unsupported. AWG seeks not only for a prudent amount related directly to prospective stock issuances, but also for any "unrecovered" costs from prior issuances. (Tr. at 690) The Commission finds such treatment of prior "unrecovered" costs inappropriate in setting prospective rates. The Commission agrees that including some level of valid, sustainable, measurable, and material flotation costs in equity return is appropriate and finds, given Dr. Morin's agreement with the formula used in Staff's analysis, that appropriate recognition of flotation costs is provided by that analysis. (Tr. at 689, 1068-1069) As to AWG's request for a "risk adjustment" of an additional 30 basis points, the Commission finds no credible evidence to support AWG's contention that it faces above average risk to its demand because of lower electric prices in competition. As noted in testimony, while electric prices may be lower in AWG's territory, so are gas prices. Nor is there any demonstrative evidence that AWG's size requires a risk adjustment. As noted by Staff witness Brown, were AWG publicly traded, it would likely trade as a small cap company. Mr. Brown's sample includes such companies and he has, therefore, appropriately captured the impact of that level of risk in his cost of equity calculation. (Tr. at 668-669)

In view of the foregoing, the Commission finds that Staff's equity range of 9.2% to 10.1% is reasonable and supported by substantial evidence of record. The Commission notes that the equity

returns recommended by the other parties, ranging from 9.24% to 9.9% based on different approaches and methodologies, all fall within Staff's equity range. Further, we find that Staff's equity range has been based on an appropriately executed DCF, as measured against the results of Staff's own RP analysis. Mr. Marcus recommended that his CAPM analysis, reflecting pension fund managers' expected returns and producing an equity range of between 8.5% to 9.9%, be used as a check for the reasonableness of the DCF results. (Tr. at 65-66) The Commission, therefore, finds no dispute from the AG regarding Staff's recommendation in this regard. Mr. Tinsley originally recommended the Commission adopt the last approved equity return of 9.9% as a maximum for AWG, testifying that AWG had not justified its return on equity request. (Tr. at 1162) In Surrebuttal, Mr. Tinsley recommends that the Commission set the equity return giving consideration to all models, to current industry risks, and to any offsetting risk mitigating tariffs or treatment, and giving effect for flotation costs. (Tr. at 1239) The Commission, in accepting Staff's equity range of 9.2% to 10.1% as reasonable, has given consideration to those areas as recommended by CEUG and finds no dispute by Mr. Tinsley of Staff's recommended equity return of 9.7%. Finally, Mr. Cassidy proposes an equity return of 9.24% based upon his own DCF analysis under three different assumptions. Equity returns resulting from these three analyses, range from 7.91% to 11.24%. (Tr. at 1054-1057) Given that Staff's recommended return on equity of 9.7% would fall within that range, the Commission finds that Mr. Cassidy's model and evidence generally supports, and does not contradict, Mr. Brown's analysis or his conclusions.

The Commission also notes Mr. Tinsley's recommendation that consideration be given to a standardization of the process by which overall return is determined in order to simplify and

streamline the process. (Tr. at 1162) The Commission finds that the evolutionary nature of regulation coupled with the reservation of parties' rights to pursue differing positions in view of changes in markets and other circumstances make standardization of the most esoteric of rate setting components not feasible at this time.

Operating Expenses

Issues still in dispute regarding AWG's operating expenses relate to: *advertising, dues and fees*; *payroll and payroll taxes*; *fringe benefits*; *officers and directors insurance*; *uncollectible accounts expense*; and *revenue conversion factor.*

A. Advertising, Dues, and Fees-Market Penetration Study

AWG's original filed revenue requirement eliminated certain promotional advertising, dues and fees, and lobbying expenses and contributions to various organizations. Staff witness Hilton[14] proposed additional adjustments removing other lobbying expenses, business gifts, additional contributions, private club fees, certain professional dues and subscriptions, certain trips, and unsupported expenditures. (Tr. at 1390) AWG witness Morgan objects to the removal of $19,700 in costs related to AWG's biannual survey, testifying that the survey, conducted since 1987, "helps AWG better understand and track household penetration, appliance saturation and customer satisfaction." Mr. Morgan states that "(t)racking these trends, helps AWG understand how to focus and utilize our marketing assets more efficiently to maintain market share and preserve base load." Further, Mr. Morgan notes that Staff allowed the recovery of those costs in its last rate case. (Tr. at 335-336) Mr. Hilton notes that Ark. Code Ann. §23-4-207 allows, for ratemaking treatment,

[14]As previously noted, Mr. Hilton adopted the pre-filed testimonies of McGarity. (Tr. at 1376 -1378)

advertising which provides information on utility service or ways consumers can conserve energy or reduce peak demand or information regarding rates and rate structures or economic development in the state and specifically excludes "Promotion Advertising" designed to encourage consumers to select or use a utility service. Mr. Hilton testifies that, given the rationale provided for the study, it appears that the study is "focused on perceived corporate image, local visibility and competition." (Tr. at 1405)

The Commission finds Staff's adjustment appropriate. Costs of a survey conducted to determine the penetration of gas appliances owned by and customer satisfaction of captive utility customers are not appropriately borne by those captive customers. The Commission also notes Mr. Morgan's own testimony specifically advises that the survey's purpose is to encourage customers to use utility service, or, as he testified, "to maintain market share." (Tr. at 335-336) The Commission finds no evidence that the Study relates to those areas addressed in Arkansas statutes and which are allowed for recovery in rates. The Commission, therefore, finds Staff's adjustment to remove these costs from revenue requirement consideration appropriate.

B. Payroll and Payroll Taxes

Staff and the Company differ on the appropriate payroll and payroll taxes related to SWN to include in revenue requirement. Although sharing the same method to calculate base payroll, these parties differ in their calculation of bonuses. In addition, the AG states that AWG bonuses are calculated incorrectly and that any corrected levels should be shared equally between AWG stockholders and AWG ratepayers. The AG's adjustments would also impact related payroll tax levels included in revenue requirement.

1. **Bonuses:**

In calculating its expected level of SWN bonuses to be included in pro forma payroll, Staff witness Williams[15] used a three year average of bonuses paid in 2002 through 2004 but excluded 50% of the total from revenue requirement. Ms. Williams states that, because, as described in pertinent proxy shareholder meeting reports, "most of the SWN bonuses criteria relate to profits, cash flow, net operating income, and meeting certain operating expense budgets", it is proper to have the expense of those bonuses shared equally between ratepayers and stockholders. (Tr. at 1432-1433) AWG witness Morgan recommends that the Commission allow 100% of the SWN bonuses as part of revenue requirement, noting that Staff does not propose that these bonuses are either excessive or imprudent or that the allocation is unreasonable, that these bonuses attract and retain quality personnel who support AWG through executive guidance and shared services, and, therefore, that they should be treated no differently than are the bonuses for AWG which Staff allowed. (Tr. at 341-342) Staff witness Williams states that the adjustment is not premised on whether the bonuses are imprudent or unreasonable, but rather because the incentive pay is directly dependent upon those financial performance goals which are appropriately shared by ratepayer and shareholder. (Tr. at 1417)

AG witness Marcus testifies that (1) an arithmetic error of $4,392 in AWG's spreadsheet should be corrected, (2) AWG included $100,000 in pro forma bonuses for the new Executive Vice President position, but had actually paid only $60,000 in 2004, reducing

[15] As noted earlier, Staff witness Williams has adopted the testimony of witness Kersten.

the prorated amount to be included to $72,000, and (3) he recommends that, given the benefits provided the stockholder as well as the ratepayer, SWN and AWG bonuses should be shared equally between stockholders and ratepayers. Mr. Marcus notes that such disallowance is generally consistent with his and Staff's recent recommendations in this regard. (Tr. at 68-70) AWG witness Morgan initially disputes any arithmetic errors, testifying that Mr. Marcus has misinterpreted the spreadsheet and failed to recognize that the $100,000 bonus for the Executive Vice President is, in fact, a three year average. Finally, Mr. Morgan reiterates his objection to any disallowance of the prudently incurred bonuses, claiming that Mr. Marcus provides no reason for disallowance other than it is not good public policy to allow 100% of bonuses. (Tr. at 348-349)

The Commission finds Staff's exclusion of 50% of SWN bonuses to be appropriate. As noted in its own proxy statement, bonuses paid to SWN executives are not directly tied to any service criteria specifically for AWG utility service but rather are more focused on areas of benefit for stockholders. However, given that some of these same areas of focus may provide indirect benefits to AWG and, consequently its ratepayers, it is appropriate to include some portion of those bonuses as part of AWG's revenue requirement. In this regard, the Commission approves Staff's proposed inclusion of 50% of the SWN bonuses in revenue requirement.

The Commission finds that Mr. Marcus has erred in his interpretation of AWG's worksheet and in the setting of the Executive Vice President's bonus level and that no adjustment is necessary. In addition, the Commission finds that AWG bonuses are tied directly to AWG utility service and, thus, are appropriately included in revenue requirement. In addition, the Commission notes that the

operating results for which bonuses are provided AWG employees differ from those of SWN. Cost savings and increased efficiencies on AWG's system directly benefit ratepayers prospectively, through delays in rate case filings or lower rates. The Commission, therefore, finds that disallowance of bonuses for AWG's personnel is not appropriate given the direct benefits provided ratepayers.

2. **Restricted Stock Rights**:

AG witness Marcus has also asked for disallowance of the stock benefits AWG requests, citing the significant increase in those amounts and the increased allocation from SWN to AWG. Mr. Marcus argues that such bonuses, in view of a $10 million rate increase request, reflect benefits, not to ratepayers, but to stockholders and, as such, all such stock benefits should be paid by those stockholders. (Tr. at 71-72) Mr. Morgan rebuts Mr. Marcus' characterization of stock benefits, testifying that these expenses are, in fact, simply part of a complete compensation package and should be included in total in revenue requirement. (Tr. at 348-349)

The Commission, as with its finding for cash bonuses, finds that such benefits for AWG employees are also of direct benefit to AWG ratepayers, but also finds that, given the criteria outlined for SWN employees, a sharing between ratepayer and stockholder is appropriate and that Staff's proposed 50% adjustment is appropriate.

3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential

to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

1. **Uncollectible Accounts - *Normalization***:

Staff, AWG, and CEUG propose to include as part of the revenue conversion factor the latest five year average percentage of uncollectible accounts to revenues, which the parties contend represents a more normal level for that component, taking into account the "volatility in gas prices and changing weather." (Tr. at 362-363, 1294, 1446) Mr. Marcus proposes that a three year average excluding the years 2000 and 2001 represents a more reasonable percentage, testifying that the year 2000 includes an uncollectible accounts level which is atypically low, while the year 2001 includes one which is atypically high. (Tr. at 129) Alternatively, should a 5-year average be adopted by the Commission, Mr. Marcus recommends that the Commission not accept Staff's updates to the time periods over which the five years will run. Mr. Marcus testifies that use of the more current time period skews further the resulting 5-year average by removing the year containing the atypically lower balance without also excluding the year with the atypically higher one. (Tr. at 129-130)

The Commission finds that the most current average of actual uncollectible write-offs represents the most known and measurable level available and should be adopted. Further, the Commission finds that the basis for adopting averages over a contemporary and sufficient time period is to both capture the most current information while smoothing the variations from year to year. The assumption made in using averages is that both normal and extreme activity will be randomly captured by use of the unadjusted average. Mr. Marcus proposes to remove completely certain chosen years because the activity in those years was "atypical", leaving him with only three remaining years upon which to calculate the balance. The Commission first finds that the three year

average proposed by Mr. Marcus does not contain sufficient data. In addition, the Commission finds that Mr. Marcus' attempt to 'cherry-pick' the years to be included, excluding any he finds 'atypical', undermines the reason for using the average of several years' actual data, randomly chosen. The Commission, therefore, rejects Mr. Marcus' proposals and finds that Staff's proposed updated five-year average should be incorporated into the revenue conversion factor.

2. Other Revenues - *Late Payment Charge Revenue:*

AG witness Marcus recommends, with the support of CEUG witness Tinsley (Tr. at 75-76, 1294), that the revenues for late payment charges ("Late Payment Charges"), as a percent of total revenues, should also be included in the conversion factor and used to calculate revenue requirement. Mr. Marcus testifies that this factor for Late Payment Charges, similar to uncollectible accounts, is tied to revenues. Further, he notes that adding it to the conversion factor recognizes that, as overall revenues and rates increase, customers who pay their bills late will increase; thus, revenues for Late Payment Charges will increase. Mr. Marcus testifies that the increase in Late Payment Charges would be 0.6329% of total revenues. (Tr. at 75)

As support for including Late Payment Charges in the revenue conversion factor, Mr. Marcus first notes that Late Payment Charges have been stable as a percent of revenues over recent years. Second, AWG's proposal to set these charges as a fixed amount in revenue requirement effectively assumes that these Late Payment Charges will remain fixed at current levels, even with increasing rates and higher customer bills. That assumption, Mr. Marcus asserts, is not logical. (Tr. at 130)

Mr. Morgan testifies that revenues from Late Payment Charges are generated from two different types of customers: those customers who cannot pay their bills, and are written off, the largest group; and the other smaller group of customers who are simply late in paying their bills. Mr. Morgan testifies that, while Late Payment Charges related to customer balances written-off may be predictable, Late Payment Charges tied to those customers only paying late is not. Mr. Morgan contends that, absent a direct relationship between revenues and these charges, Late Payment revenues do not lend themselves to inclusion in the factor tied to revenue changes. (Tr. at 354-355)

For the reasons argued by AG witness Marcus and CEUG witness Tinsley, the Commission agrees that late payment revenues, as a percent of total revenues, should be included in the conversion factor. The AG has testified that Late Payment Charges Revenues, as proposed by AWG, are 0.6329% of revenues. (Tr. at 75) The Commission finds that percent reasonable. Therefore, the conversion factor should be changed accordingly and used in the calculation of the revenue requirement.

3. **Uncollectible Accounts - *By Rate Class*** :

CEUG witness Tinsley recommends that AWG should be ordered to calculate and apply conversion factors on a class by class basis because the percent of uncollectible accounts varies from class to class, with the larger customers experiencing significantly smaller accounts receivable write-offs as indicated by AWG witness Campbell. Mr. Tinsley also proposes that, if the data is limited, the Commission should still require conversion factors set by class, using the data available to estimate each class. (Tr. at 799, 1294-1295)

Ms. Campbell testifies that AWG has been keeping this data by class, but only for a very short time, and that it would be inappropriate to assign these costs directly to class on that limited data. (Tr. at 799-800)

The Commission finds that, given the lack of data, it would be inappropriate to substitute the current average, total-company revenue conversion factor, which is based on known and measurable activity, with several individual class conversion factors based on either too little data or an unsubstantiated estimate. Mr. Tinsley's proposal is hereby rejected and the Commission finds that Staff proposed total-company approach should be used.

In view of the foregoing, the Commission finds that the revenue conversion factor as proposed by Staff, with the exception of the inclusion of late payment revenues, shall be incorporated into the calculation of revenue requirement in setting prospective rates.

Cost of Service
Allocation of Revenue Requirement to Rate Class

The following elements of AWG's cost of service continue to be contested: *Billing Determinants* - Weather Adjustment and Growth Adjustment, *Functional*[16] *Allocation of Plant and Plant-related Revenue Requirement Elements*, Production/Gathering Plant, Storage Plant, Transmission Plant, Distribution Plant, General Plant, and, specifically, *Gas Stored Underground*, *Meters - B-4 Customers*, *Account 336 - Purification Equipment*, and *Uncollectible Accounts*.

[16]Current functions related to AWG's system include: Gathering/Production, Storage, Transmission, Distribution, and General.

Additionally, still outstanding are the parties' differences with regard to the appropriate calculation of the *Coincident Demand* and the *Non-Coincident Demand.*

A. Billing Determinants

Staff, AWG, and the AG have adopted the billing determinants as proposed by Staff. CEUG, however, recommends (1) an adjustment should be made to weather adjust the determinants for the B-4 and B-5 rate classes, and (2) that, absent adoption of combined billing guidelines, billing determinants be adjusted to add all meters held by combined billing customers. CEUG also proposes that separate rates for sales customers and transportation customers be set, which will require a reapportionment of billing determinants between the two.

1. <u>B-4 and B-5 Rate Classes:</u>

CEUG witness Tinsley proposes that rate schedules B-4 and B-5 be adjusted for weather in the same manner that residential and the other business classes have been adjusted which, irrespective of how minor, is easily accomplished. (Tr. at 1173-1175) AWG witness Campbell, with support of Staff witness Swaim, objects to the adjustment as inappropriate, noting that these customers are not materially affected by weather, with changes for B-4 limited to just .86% and for B-5, just .28%. (Tr. at 772-773, 1475-1476) Mr. Tinsley responds that Ms. Campbell has already calculated the adjustment and to not treat these customers consistently would result in discriminatory and non-uniform treatment of classes. (Tr. at 1287-1288)

The Commission finds that, given the immateriality of any adjustment to be made, it is unnecessary to adjust usage for weather for these large customers. The Commission notes that the

rate making process is not precise and that, because of this, consideration must be given to the materiality of any proposed change. In this regard, the Commission finds adjustments to billing determinants of less than 1% and less than ½ of 1% immaterial and, as they relate to the entire process, the Commission finds them significantly immaterial. The Commission also finds that its charge is to set rates for the classes that are not unduly discriminatory and, in this instance, failure to apply an immaterial adjustment does not constitute undue discrimination.

2. Master Metering and Combined Billing:

CEUG recommends adoption of guidelines to effect a policy covering master metering and combined billing which will be applied consistently to all qualifying customers. (Tr. at 1154-1157) Mr. Tinsley recommends, however, that, should the Commission not adopt his proposed guidelines, it is appropriate to include all the meters held by combined billing customers in the total count of billing determinants. Mr. Tinsley testifies that, because combined billing is not offered on a consistent basis to all customers, it is stockholders, not ratepayers, who should be required to absorb any unrecovered costs resulting from providing combined billing service. (Tr. at 1177-1179, 1288-1289)

The Commission finds no evidence in this proceeding which indicates that AWG provides this service absent economic rationale or in a discriminatory manner. Therefore, the Commission finds no need to adjust billing determinants to reflect additional meters held by combined billing customers.

3. **Sales Rates and Transportation Rates:**

CEUG recommends separation of transportation service from sales for purposes of allocation, with billing determinants recognized for the separate service.

The Commission finds that, as discussed later in this Order in our findings regarding Tariff Provision and Rate Design, stand-alone calculation of a transportation service rate is not appropriate and, therefore, there is no need to adjust billing determinants. In view of the foregoing, the Commission finds that the billing determinants, as adopted by Staff, with support of AWG and the AG, appropriate and orders adoption of those determinants for AWG's cost of service and rate design in this docket.

B. Functional Allocation of Plant and Plant-related Revenue Requirement Elements

AWG and Staff have both recommend a Cost of Service ("COS") using the cost classifications and allocation methodologies which reflect the COS to which the parties agreed in the Stipulation and Settlement Agreement filed in AWG's last rate case, Docket No. 02-227-U, and which the Commission approved. (Tr. at 1529, 1544) Staff witness Green testifies that she has some corrections to Ms. Campbell's proposed COS (Tr. at 1536-1537), which Ms. Campbell has incorporated into her recommendation. (Tr. at 782, 788, 793, 796) No other parties provided a detailed COS. (Tr. at 1544) The AG, NWAGC, and CEUG each provided isolated recommendations regarding appropriate classification and allocation on a function by function basis. The classification of costs as customer, demand, or commodity will have a direct impact on the level of costs allocated to each customer class and the amount set for the customer charge for each class. (Tr. at 1546)

1. **Production and Gathering Functions:**

AWG witness Campbell and Staff witness Green have classified costs on an account by account basis. They allocate each account (1) using only a commodity, or volumes factor, (2) using only a demand factor, or (3) equally to demand and commodity and applying an appropriate factor. (Tr. at 1553) Plant designed for peak but used throughout the year was classified as demand and allocated on the average and peak method[17] by Ms. Campbell and Ms. Green. (Tr. at 777) Ms. Campbell and Ms. Green classified producing land, rights of way, other land and rights, and field lines as commodity and allocated those costs on total volumes. (Tr. at 777) As the physical location of assets move further from the wells, these assets are classified by Ms. Campbell and Staff witness Green as 50% demand/50% commodity and are allocated on average and peak for demand and volumes for commodity. (Tr. at 777-778) Finally, Ms. Campbell and Ms. Green have classified assets as they move closer to transmission as demand related and are allocated on average and peak. (Tr. at 778) AG witness Marcus recommends that essentially all plant be classified as commodity and allocated on volumes, with an alternative recommendation that any demand classification be allocated on a "coincident demand factor to include the loads of curtailed customers on either a 100% load factor or a normal winter basis." (Tr. at 1553) NWAGC witness John recommended that all production and gathering be classified as demand and be allocated on a curtailed peak demand factor. (Tr. at 1553) Mr. John testifies that the gathering and

[17] "The average and peak allocation factor for each class was calculated by weighing the average demand by the system load factor and the peak demand by one minus the system load factor. . .." (Tr. at 750-751)

production costs at issue are fixed costs, incurred to meet the peak demand requirements of AWG customers, and, as such, are more appropriately classified as 100% demand and should be allocated on curtailed peak. (Tr. at 1112-1113) Further, he testifies that allocation of demand costs should reflect that transportation customers, supplying their own commodity, will use gathering and production very little. Further, he testifies that interruptible, or curtailment[18], customers have no rights to the system at peak load, and, therefore, should be allocated based on peak less those interruptible customers.[19] (Tr. at 1113) CEUG witness Tinsley recommends recovery of production plant through the Cost of Gas Adjustment Clause ("CGA") (Tr. at 1316-1317) and that Fuel and Lost and Unaccounted For Gas ("LUFG") should be allocated based on demand, recommending use of curtailed peak. (Tr. at 1313-1314) Mr. Tinsley testifies against AWG's use of an average and peak method, stating it inappropriately assigns fixed cost to the commodity charge, violating the principles of cost-causation and resulting in subsidy of low-load factor customers. (Tr. at 1186-1187)

Ms. Green and Ms. Campbell oppose both Mr. Marcus' proposed classification of production and gathering as commodity to be allocated all volumetrically and his alternate proposal that, if any is classified demand, that the peak factor used to allocate be adjusted to include curtailment loads at 100% or be calculated on a normal winter basis. Both witnesses note that allocating only on volumes fails to recognize the operation of the system, which is

[18]Curtailment and Interruptible are used interchangeably and refer to those customers or services subject to AWG's curtailment policy contained in their tariffs. (Application, Proposed Tariffs, Policy Schedule 4.1)

primarily used in winter and on peak and is more appropriately allocated recognizing that use. Ms. Campbell states that it is also not appropriate to classify all of the fixed costs for these functions as demand, noting that such classification also fails to recognize the use of the system, which serves to meet peak but also serves off peak needs. In addition, Ms. Campbell testifies that Mr. Tinsley's recommendation to recover these costs through the CGA is not appropriate given that (1) such treatment effectively classifies the plant as all commodity, which would not recognize the use of this plant, and (2) these costs do not fall within the Commission's policy for automatic adjustment, exhibiting no extreme volatility or unpredictability, or being outside company management control. (Tr. at 778-780, 781-782, 1553-1554)

In general, with regard to allocations of costs to customer classes, the Commission finds that an appropriate cost of service should be conducted looking at each function on an individual account basis as both Staff and AWG have done. Additionally, as both Staff and AWG have done, interpretation of 'cost causation' relates directly to a fair allocation of cost to reflect the use of the plant by the customers who benefit. The Commission finds that any interpretation of "cost causation" which assigns all fixed cost to demand and peak allocation, simply because the costs do not vary directly with volumetric use, fails to reflect the use of the system nor does that interpretation appropriately assign costs to those customers who benefit by that use.

With regard to the classification and allocation of production and gathering, the Commission finds Ms. Campbell's and Ms. Green's analysis of plant, done on an account by account basis to

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[19] Peak load less the peak load of curtailment customers is Mr. Tinsley's defined "curtailed peak."

determine the function and use of each plant component, the most supportable method in determining appropriate classification of this plant. The Commission finds the resulting determinations both reasonable and supported by the descriptions of those functions in testimony. The Commission finds that AWG and Staff have appropriately recognized each component as either related to commodity, to demand, or to both. In this regard, those functions which related specifically to certain production and gathering systems have been classified as commodity and allocated as such.

The Commission also notes that many system components for gathering and production are designed to meet peak day and should appropriately be allocated to recognize the use and benefits enjoyed by customers who are guaranteed service on peak day. (Tr. at 778-780, 1553-1554) However, the Commission also finds that any off-peak use and benefits enjoyed by customers of the same system components dictate a fair allocation of costs to those customers as well. (Tr. at 778-780, 1553-1554) It is therefore the Commission's finding that neither Mr. John, who recommends allocation solely on demand, using a peaking factor, nor Mr. Marcus, who recommends allocation solely on commodity, propose methodologies which appropriately recognize the use of the system by allocating fairly to the customers who benefit.

Neither does the Commission find appropriate Mr. Tinsley's proposal to have these costs recovered strictly through the CGA. The Commission finds that gathering and production represent functional support of the entire system. By moving recovery of these costs to the CGA, Mr. Tinsley ensures that no transportation customers will be held responsible for their use of the production and gathering system. In addition, the Commission finds, under its consideration of costs which would

qualify for recovery under an automatic adjustment clause, (see the Commission findings on the REP), wholesale automatic recovery of all individual costs related to these functions is not appropriate. The Commission, therefore, finds that the classification and allocation of costs as proposed by Staff and AWG for production and gathering are both reasonable and supported by the record and should be used in the cost of service.

2. **Storage Function**:

The parties to this docket, other than CEUG, agree on the classification and allocation of storage as proposed by Staff witness Green and supported by AWG witness Campbell. CEUG witness Tinsley alternatively recommends that no transportation customer should be allocated storage, given that the Company cannot delineate the level at which storage supports transportation service imbalances. It is his overall recommendation that storage costs be recovered as part of the CGA, effectively eliminating all transportation customers from storage cost responsibility. (Tr. at 782-784, 1317) Ms. Campbell testifies that, in fact, transportation customers do heavily utilize storage and provides documentation (Ex. at 451-456) indicating that transportation customers' "nominations do not match hourly volumes and, therefore, must utilize storage." (Tr. at 783)

First, with regard to Mr. Tinsley's request to also roll storage costs into the CGA, the Commission finds, as it did for gathering and production plant, Mr. Tinsley's proposal inappropriate and rejects it. The Commission also finds that, based on the evidence provided regarding the imbalance activity of transportation customers, it is clear that these customers rely heavily on this service on a daily basis. The Commission additionally notes that, as an integral part of AWG's

system, storage, as does transmission, supports the overall operation of that system. The Commission finds that allocation as proposed by Staff and AWG appropriately recognizes and assigns costs to transportation customers, both for their balancing needs and as part of the storage function's overall support of the system.

3. **Transmission Function**:

As noted by AWG witness Campbell, and accepted by Staff witness Green, AWG and Staff classified transmission plant as demand related and allocated the costs on an average and peak method, which gave greater weight to peak use. Ms. Campbell testifies that she allocates the peak using her calculated coincident peak demand factor. (Tr. at 752-753, 1544, 1555-1556) Ms. Campbell testifies that the average and peak method reflects that transmission plant was built to meet the peak load but is also used to meet the daily demands of all customers. (Tr. at 752-753) Further, she testifies that the average and peak method is an accepted method of allocation. (Tr. at 785-786) Ms. Campbell testifies that it is not appropriate to classify and allocate 50% of transmission based on commodity, as proposed by the AG, noting that the system is not built for individual customer demand but rather for a maximum simultaneous peak day. (Tr. at 786) Nor, she testifies, is it appropriate to allocate all of transmission plant on a curtailed coincident peak, as proposed by NWAGC witness John, which fails to capture the off peak use of the system (Tr. at 785)

AG witness Marcus recommends that the Commission allocate 50% of transmission plant on peak and 50% on the commodity factor, testifying that this would follow the lead of Arkansas Oklahoma Gas Company and recognize that transmission plant is sized to meet

peak demand but it is used on a sustained basis. (Tr. at 92-93) Mr. John and CEUG witness Tinsley both testify that all transmission plant is fixed cost and should be classified to demand and allocated on curtailed peak load, not commodity, and further recommend that any variable transmission function costs be assigned to commodity and allocated on that basis. (Tr. at 1103, 1114, 1206-1207)

The Commission finds that Staff's and the Company's classification and allocation of the transmission plant appropriately recognizes the design of the system, which is built to meet the system peak and is also designed to meet daily demand. The average and peak method adopted has assigned a more heavily weighted portion of transmission plant to the peak allocator which appropriately recognizes that the system is primarily designed to meet the peak day. The remaining allocation to customers using the average allocator assigns the less weighted cost to the transmission plant's daily demand. The Commission rejects the AG's assignment of a portion of costs to commodity, noting that, classification as demand and application of the average and peak method more accurately reflects the weight to be given the system design and use. The Commission also rejects, as discussed previously, equating fixed cost with peak-only usage and, thus, peak-only allocation. We therefore reject both Mr. John's and Mr. Tinsley's recommendation to allocate all fixed transmission cost on peak. Their proposal simply fails to appropriately recognize the customer use of and benefits provided by that plant. Therefore, the Commission orders the use of the average and peak method as proposed by Staff and AWG for transmission plant allocation of costs.

4. <u>Distribution Function/Mains</u>:

Items of classification and allocation of distribution mains which remain in dispute

are principally (1) the method by which distribution mains will be classified between demand-related and customer-related and (2) the allocation methods which should be used to assign mains to each class.

a. Classification:

Both the Company and Staff, with support of CEUG witness Tinsley, have classified distribution mains to demand and customer, using AWG's proposed zero load main method, resulting in allocation of 42.5% of Mains as customer-related and 57.5% of mains as demand-related. (Tr. at 1547) AWG witness Campbell explains that she has used what she describes as the zero load method[20] in place of the more commonly used zero intercept method given that the data necessary to use the latter is not available and given the zero load's simplicity. While the zero intercept method relies on regression analysis, the zero load method only requires that the costs of pipe, adjusted for pipe-related material, be identified. The average cost for each pipe size is calculated and, in this instance, with 80.77% of all pipe installed over the last three years being 2-inch pipe, Ms. Campbell used the net cost of 2-inch pipe to set the customer component. Mains were classified to the customer component at 42.5% and the remainder classified to demand. (Tr. at 752-756, 787-789)

AG witness Marcus proposes that all mains be classified as demand, or, as an alternative, set the cost per foot of mains at a lower level to reflect the results of other

[20]Ms. Campbell has expanded her definition to deduct more pipe-related material cost, as proposed by Ms. Green, which reduces the estimated cost per foot of pipe and the amount to be classified as customer. (Tr. at 788)

classification methods, including his proposed minimum connection method. (Tr. at 96-103, 132-134) Mr. Marcus testifies that mains are a common cost, not assignable to individual customers, and that the method AWG proposes is flawed, assigning too much cost to small customers. (Tr. at 97-100) Further, he notes that, irrespective of any flaws in data used by AWG to perform its own zero intercept analysis as discussed by Ms. Campbell (Tr. at 789-790), the results would provide a reasonable 35% classification of main costs to the customer component. (Tr. at 133-134)

NWAGC witness John recommends rejection of Mr. Marcus's proposal to recognize no customer costs because it significantly departs from prior Commission treatment, which recognizes that costs which are set, irrespective of pipe size and not related to throughput or demand, are customer related. (Tr. at 1115-1117) Further, both Ms. Campbell and Mr. John note that the zero intercept study recommended by Mr. Marcus has inappropriately excluded the northeast region and excluded plastic pipe and should not be used. (Tr. at 790, 1117)

The Commission finds that AWG's proposed alternative method, the zero load method, as further refined by Staff witness Green's adjustment for pipe-related material, is a reasonable replacement for the use of the zero intercept method, given the limitations outlined by Ms. Campbell. (Tr. at 754-755) That finding is also supported by the fact that the zero load method's results reflect, in close proximity, the "customer-related classification (which) . . . would result from using the "Handy-Whitman Index of Public Utility Construction Costs" to index the installation cost per foot (used) . . . in the last rate case." (Tr. at 1549-1550) The Commission rejects Mr. Marcus's

proposal to recognize no customer related costs for distribution mains and his proposition that these costs reflect, more appropriately, only demand. The Commission notes that the AG's proposal fails to recognize the use of mains, which is in part to meet customer's peak, but must also reflect the initial design and installation, which effected service to those customers served directly from the line. The Commission also rejects the alternative classification assignment methods which the Commission finds all rely heavily on limited data. (Tr. at 753-754, 789-790)

b. Allocation:

Both Staff witness Green and AWG witness Campbell have allocated distribution mains, classified as customer, on an annual customer count basis. (Tr. at 1536, 755) There appears to be no dispute regarding that method. In addition, both Ms. Green and Ms. Campbell, as supported by CEUG witness Tinsley, (Tr. at 1252), have allocated distribution mains classified as demand on the non-coincident peak basis. (Tr. at 1536, 756) Ms. Campbell explains the demand allocation using the non-coincident peak, testifying that the main is designed "to meet a specific customer's maximum demand or a specific group of customers' maximum demand in a certain area." (Tr. at 756) Further Ms. Campbell testifies that non-coincident peak reflects that mains are sized to meet the "customers' peak loads and not the system's peak load . . ." which means that distribution mains must be correctly sized regardless of when the customer experiences peak. (Tr. at 792)

AG witness Marcus recommends that all mains be allocated on the average and peak method. He explains that, while off peak users should be assigned less

cost, to allocate these costs only on peak effectively provides service to off-peak at no cost. (Tr. at 98-99) NWAGC Witness John recommends that the demand costs of distribution plant be allocated on the curtailed non-coincident peak, testifying that the capacity related portion of the plant was built to meet peak day and, given that curtailment customers have no rights to that plant at peak, they should be assigned none of the demand costs. (Tr. at 1119)

The Commission finds the allocation of demand for distribution mains on a non-coincident peak basis, capturing all customers' peak, including curtailment customers, is appropriate. As discussed by Ms. Campbell, mains are designed to meet the peak of all customers served by the main at anytime those customers call on the system. As such, each customer should be allocated full cost of that demand on the system. The Commission rejects Mr. Marcus' proposed allocation of mains on the average and peak method. His rationale for its adoption, to assign cost to off-peak users, is fully addressed in the more appropriate method proposed by Staff and AWG. That method allocates costs based on the design of the main which allows each customer to make full demand for service at any time. For this same reason, the Commission rejects Mr. John's proposed allocation which excludes curtailment customers. The Commission finds that AWG's and Staff's proposed non-coincident peak for allocation of the demand component of distribution mains should be used in calculating the cost of service in this docket.

C. Working Capital Assets/ Storage Gas

AWG witness Campbell testifies that she has classified and allocated gas stored underground, a working capital asset, in the same manner as storage plant. (Tr. at 758) CEUG

Witness Tinsley, referring to his testimony regarding classification and allocation of Storage Plant as support, recommends that gas stored underground (1) should be recovered through the CGA, (2) should not be allocated to transportation customers, and (3) should not be allocated to customers whose billing determinants have not been weather adjusted. (Tr. at 1208-1209) Ms. Campbell, as supported by Staff witness Green (Tr. at 1554-1555), refers to her testimony regarding storage plant and testifies that transportation customers do use storage and, therefore, recovery of gas stored underground using the CGA is not appropriate because it does not assign any of these storage costs to transportation customers. Further, she notes that these costs also do not meet the criteria for recovery of costs through an automatic adjustment clause. (Tr. at 793-794)

Consistent with our findings as to CEUG's recommendations to recover production and gathering and storage plant costs through the CGA, the Commission finds Mr. Tinsley's proposal for recovery, through the CGA, of costs related to gas stored underground also inappropriate and rejects it. The Commission again notes that this revenue requirement item does not meet the criteria for automatic treatment, given that it is not a significant cost, exhibiting extreme volatility and trending in one direction. Nor is it outside the control of management. The Commission, again, finds that, as seen by their imbalance record, transportation customers utilize AWG's storage system and appropriately should bear a share of those costs. The Commission finds that gas stored underground should be classified and allocated as recommended by AWG and Staff.

D. Meters - B-4 Customers

In his testimony, CEUG witness Tinsley observes that the average cost of meters for B-4 customers, resulting from the meter study performed by AWG witness Campbell and used to assign

costs to meters, are higher than the average meter cost for B-5 customers and labels the difference as "an obvious anomaly" which should be corrected. (Tr. at 1314-1315)

The Commission finds nothing in the record to support Mr. Tinsley's conclusion that the costs are incorrect nor does Mr. Tinsley provide any evidence in support of his supposition that a correction is needed. The Commission, therefore, finds that no correction is necessary and there are no changes to the cost of service required because of B-4 customer meter cost.

E. Account 336 - Purification Equipment

Based on the function of purification equipment which removes impurities from and conditions gas, Staff witness Green recommended a change in AWG's original classification of this account as demand-related and its allocation on the average and peak method to classification as commodity and a volumetric allocation. (Tr. at 1537) AWG witness Campbell agreed with the change. (Tr. at 782) However, CEUG witness Tinsley disagrees with classification of this equipment as commodity related, testifying that the cost of this equipment is a function of capacity, and, while it should actually be allocated to customers based on coincident peak, he would, alternatively, recommend AWG's original allocation on average and peak. (Tr. at 1314)

Mr. Tinsley adopted the position that all fixed costs must be demand costs and assigned to customers only on their peak simply because those costs do not vary with throughput. The Commission, as discussed previously, adopts allocation methods which recognize the appropriate matching of any cost to those customers benefiting from that cost. The Commission finds that the use of the equipment which purifies natural gas benefits all customers receiving that gas and that the benefit is equally applicable to each unit taken. Therefore, the Commission finds Staff's proposed

classification as commodity, with allocation based on delivered volumes, wholly appropriate and approves that treatment.

F. Uncollectible Accounts Allocated to Class

CEUG witness Tinsley recommends that uncollectible accounts be directly assigned to each customer class, noting that current information indicates that the percent of uncollectible accounts varies from class to class, with the larger customers experiencing significantly smaller accounts receivable write-offs as indicated by AWG witness Campbell. Mr. Tinsley acknowledges that data may be limited but recommends that the Commission require direct assignment based on the information available. (Tr. at 1294-1295, 1320, 799) Ms. Campbell testifies that the Company has been keeping this data by class, but only for a very short time, and, thus, it would be inappropriate to assign these costs directly to class based on that limited data. (Tr. at 799-800)

As found with regard to uncollectible accounts used in the calculation of the conversion factor, the Commission finds that it would be inappropriate to allow direct assignment of a 'level' of costs which may not be representative of a normal and expected level in view of the limited time period over which these costs have been kept on a separate class basis. Given that these costs have been accumulated for less than a year, the Commission finds that AWG's and Staff's proposed allocation, based on historical data, is a more reliable representation of the costs expected to be incurred. The Commission, therefore, orders Staff's and AWG's proposed allocation of uncollectible accounts to rate class be used in the final cost of service.

G. Coincident Demand Calculation

The appropriate calculation of the coincident peak demand allocator, which is used in

allocation of demand under different methods, remains in dispute. At issue is the treatment of the load of interruptible or curtailment, customers[21] in determining the peak assigned to each rate class, the basis for the allocator. AWG and Staff support AWG witness Campbell's calculation, with each of the other parties proposing alternative approaches. Ms. Campbell testifies that she has adjusted the coincident peak load calculated for rate schedules B-4 and B-5 by removing one-half of the interruptible or curtailment volumes for those customers. Ms. Campbell notes that she makes this adjustment to reflect that these classes of customers were curtailed on the record peak day[22] used in making the coincident peak calculation and, therefore, an adjustment to recognize the curtailment should be made. She notes that she has removed only 50% of those volumes, recognizing that many of these customers will not experience complete curtailment, given that they will continue to receive some service in order to maintain the integrity of their plants and operations. She also testifies that, prior to adjusting the B-4 and B-5 loads, she recognized and corrected for customers in those rate classes who are deemed to be "human needs" customers, who will not be curtailed, and, therefore require no adjustment. (Tr. at 750-753)

AG witness Marcus recommends that, in calculating coincident peak, the Commission reject the Company's adjustment to remove 50% of interruptible or curtailment loads from the demand allocator. (Tr. at 89) Mr. Marcus testifies that removing these loads from the allocator fails to recognize that "interruptions (of these customers) are extremely rare." Mr. Marcus states that the

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[21] Interruptible or Curtailment Customers on AWG's system are those customers subject to curtailment should system capacity be reached.

[22] In calculating coincident peak, Ms. Campbell adjusts her peak calculation to reflect the 25 year peak experienced on December 25, 1983, on which the HDD ("Heating Degree Days") was 71. The actual HDD for highest peak in the test

system appears to be more reliable with less likelihood of interruption, citing the fact that interruptions were called with Heating Degree Days ("HDD") of between 47-57 during 1996 but, since that time, no interruptions were called, although there were some 20 days equal to or exceeding 47 HDD. He further testifies that the impact of removing these loads from the allocator is to effect steep (up to 75%) discounts for essentially firm service, with interruptions occurring once in 10 years. (Tr. at 89) Mr. Marcus testifies that there is also another reason not to adjust for interruptible load. He notes that all customers, firm and interruptible, are within the same rate class and both benefit from the allocation reduction made for interruptible service. Thus, he states, the interruptible discount serves to have smaller firm customers subsidize those firm customers in the larger industrial classes. (Tr. at 90) As an alternative, Mr. Marcus recommends that the Commission should either not reduce interruptible load and estimate a test-year demand reflective of a normal winter or set the demand for these customers based on a 100% load factor basis. (Tr. at 90)

NWAGC witness John recommends that the coincident peak factor, upon which demand is to be allocated, should be based on coincident peak with all interruptible or curtailment customers' volumes removed from the peak in each class, referring to that calculation of peak as curtailed coincident peak. He testifies that "(t)he term demand (or capacity) refers to that aspect of utility service that must be available upon the customers' demand" (Tr. at 1101) and must be available to customers with priority use on peak day. Mr. John testifies that, therefore, the allocations should reflect the fact that interruptible customers do not have priority and may, in fact, be curtailed. (Tr.

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year was 54 HDD. (Tr. at 751, 756)

at 1101) Mr. John also testifies that customers who are curtailed should not be allocated demand costs. He testifies that, because these customers do not have access to the system at peak, to assign peak costs to those customers would result in interruptible customers subsidizing firm customers, who do have access to peak. (Tr. at 1114) Additionally, because many of the customers in the rate classes at issue are transportation customers, it is appropriate to allocate using curtailed peak day because of their lower priority rights to the system, resulting in better aligning cost with cost causation. (Tr. at 1113)

CEUG witness Tinsley concurs with Mr. John's recommendation to use curtailed coincident peak, testifying that it is not appropriate to include curtailment customers in the peak allocation. (Tr. at 1206-1207, 1318). Further, Mr. Tinsley testifies that AWG also inappropriately includes in allocating cost the loads of those customers labeled "human needs" customers who already have installed back-up energy systems. These customers, Mr. Tinsley states, may, under the tariff, waive their rights and release AWG from liability and allow themselves to be subject to curtailment. Further, he states that they are willing to do so. (Tr. at 1189-1191) He testifies that these customers have not yet agreed to waive their rights because, in the last rate case, their loads were included for purposes of demand cost allocation. Mr. Tinsley states that because they were allocated these demand costs and are paying for firm service, they have had no incentive to become interruptible. (Tr. at 1191) He recommends that appropriate adjustments be made to the peak loads of the B-4 and B-5 customers to recognize those "human needs" customers willing to sign affidavits agreeing to curtailment. (Tr. at 1193)

The Commission adopts, as just and reasonable and based on the design and historical use of

the system, Staff's and AWG's adjustment to the peak factor to exclude only 50% of the non-human needs curtailment customer peak load. The Commission finds that the 50%-only reduction appropriately recognizes that part of the load is not curtailed on peak for purposes of maintaining customer plant integrity. The Commission rejects AG witness Marcus' proposal to include all curtailment customers at 100% load factor, noting that, irrespective of current history, curtailment customers do not have service rights at peak and allocation of costs should reflect that. The Commission also rejects Mr. Tinsley's and Mr. John's proposal to exclude all curtailment load from the allocator. Such an allocator would fail to appropriately recognize that many of these customers have rights to service to preserve customer plant integrity.

In addition, the Commission rejects Mr. Tinsley's recommendation to exclude from peak the load of current human needs customers who qualify under the tariff to waive firm service and essentially become curtailment customers. (Tr. at 1227-1228) The Commission would note that, as discussed by Ms. Campbell, the system has been designed to include and serve these human needs customers at peak. (Tr. at 779) Second, it is apparent that these customers have been enjoying firm service paying the same rate as interruptible customers. Third, the tariff provisions (Application, Tariffs, Policy Schedule 4.1) indicate that exclusion from interruption is an exception provided for the benefit of human needs customers and that these same customers will continue to have the rights to and benefits of firm service at essentially interruptible rates, irrespective of how costs are allocated in this docket. Finally, the majority of the qualifying human needs customers have not yet opted to waive firm service, choosing not to declare themselves interruptible, in spite of their right to do so. (Tr. at 1191) The Commission finds that the record does not support adjusting the cost

allocation in this case based on the assumption that these same customers will, in the future, chose to forego firm service which they can continue to receive at interruptible rates. These customers are, however, free to waive their exemption and begin to take service as curtailed customers so that, in the future, they will be allocated less cost and will garner lower rates. The Commission, therefore, finds that, based on (1) these customers' historical firm use, (2) the tariff provisions under which they may continue to take that firm service at essentially interruptible rates, and (3) their incorporation into system design for peak day, it is appropriate to include human needs load in peak for allocation purposes. The Commission orders that the definition and calculation of curtailed peak demand as proposed by AWG and Staff be used in the calculation of the cost of service.

H. Non-Coincident Demand Calculation

AWG and Staff witnesses Campbell and Green concur on the appropriate calculation of non-coincident peak demand with an alternate recommendation provided by NWAGC witness John. Ms. Campbell testifies that, because residential, B-1 and B-2 customers peak during the winter months and are not curtailed, their non-coincident peak is the same as their coincident peak. For other classes, she has calculated a non-coincident peak, based on historical HDD and has made no adjustments for curtailment load. (Tr. at 756-757) Ms. Campbell explains that mains are designed, not to meet the system peak, but rather to meet the peak of all customers served by the main anytime those customers call on the system. As such, each customer should be allocated full cost of that demand on the system, including interruptible loads. (Tr. at 756-757)

Mr. John renews his objection to the inclusion of any interruptible customers' load in determination of a peak allocator for these fixed costs. (Tr. at 1119)

The Commission finds that, as discussed by Ms. Campbell, distribution mains are designed to meet the customers full demand, whenever that may occur. Therefore, the non-coincident peaks of all customers must be considered and used in calculation of peak. Mr. John's proposed calculation, which eliminates all curtailment loads, fails to account for that design and use of Distribution Mains and is, therefore, rejected. The Commission finds that AWG's proposed non-coincident peak demand calculation should be used in determining the cost of service in this docket.

Tariff Provisions/Rate Design

Two tariffs for which the design or terms of use remain contested are the *Weather Normalization Adjustment Clause* ("WNA"), with its terms or continued applicability in dispute, and the *Transportation Service Tariffs*, which CEUG recommends be set on a basis separate from the non-gas portion of the sales rates. Additionally, CEUG recommends adoption of *Demand Based Rates* for transportation customers and *Declining Block Rates* for sales customers. CEUG recommends that tariff provisions for *Combined Billing and Master Metering* be set out and that *Standby Service* be defined to eliminate potential misinterpretation.

A. Weather Normalization Adjustment Clause

CEUG witness Tinsley has recommended that rates for transportation customers be designed as demand-based and that rates for sales customers be designed using a declining block structure. Because the WNA is designed to adjust for under- or over-collection of fixed costs due to weather variations, should the Commission adopt the design changes, which will effectively collect

those fixed costs, the WNA should be abolished. However, absent adoption of these rate design changes, Mr. Tinsley recommends that certain changes be made to the WNA. (Tr. at 1171)

Mr. Tinsley testifies that the WNA fails to account for a myriad of reasons other than weather which result in differences in customer usage levels, including customer growth or loss, facility expansion or use, fuel switching, and energy consumption. (Tr. at 1168) He illustrates his concern with this failing, noting that when coupling load growth with warmer than normal weather under the current rate design, the company will experience a windfall. He testifies that not only will the WNA adjust to normal levels revenues from current customers, but with load growth, will enjoy new revenues from that customer growth and additional revenues as those customers' bills are also adjusted under the WNA. (Tr. at 1168) Mr. Tinsley recommends that the Commission should therefore change the WNA so that each year's volumes are compared to the original pro forma level and adjusted accordingly. (Tr. at 1171) If the Commission chooses not to redefine the basis for the WNA, Mr. Tinsley makes other recommendations applicable to the current WNA. (Tr. at 1171)

Mr. Tinsley additionally testifies that usage, across all rate classes, exhibits some form of weather sensitivity, a fact to which Ms. Campbell admits in her testimony. (Tr. at 1169) Mr. Tinsley states that all rate schedules should be included under the WNA, noting that rate schedules B-3, B-4, and B-5 are excluded. (Tr. at 1168-1170) At a minimum, B-3 customers should be included under the WNA to be consistent with the fact that these customers' billing determinants were weather adjusted to set base rates. (Tr. at 1169-1170)

In addition, Mr. Tinsley testifies that the volumetric rates currently subject to adjustment under the WNA include variable costs, which will vary directly with usage, and therefore should not

be subject to any weather normalization under the tariff. He recommends that all variable costs be removed from the rates subject to the WNA. (Tr. at 1172)

Mr. Tinsley also objects to the exemptions from the WNA allowed for cotton ginning and grain drying customers, observing that AWG provides no evidence indicating that these customers do not use gas for weather sensitive activities. Mr. Tinsley testifies that his experience with grain drying customers reveals that these customers do use their gas service for many activities, including those which may vary with weather. (Tr. at 1170-1171) Mr. Tinsley also asserts that the fact these customers may exhibit usage outside of the winter peaking months indicates only that there may be other things affecting their usage and is not necessarily indicative of a lack of weather sensitivity. (Tr. at 1284-1285) Mr. Tinsley, therefore, recommends that these customers no longer be exempt from the WNA or that, in the alternative, AWG adopt a standard by which other customers with similar usage patterns can be eligible for exemption. (Tr. at 1172)

Both Staff witness Swaim and AWG witness Campbell testify that the purpose of the WNA is to address the impact to revenues of deviations from normal weather and not other possible reasons for deviations in customer usage. (Tr. at 808, 1476) Mr. Swaim testifies that this limitation should also be noted with regard to Mr. Tinsley's concern about "double recovery" for variable cost under the WNA, which actually is more of a concern for rate design and not the limited scope of the WNA. (Tr. at 1478)

Ms. Campbell addresses Mr. Tinsley's proposal to abolish the WNA as unnecessary in the event the Commission adopts his changes in rate design. First, as for adoption of demand based rates, only large customers' rates are appropriate for a demand-based design and they are not subject

to the WNA. As for adoption of declining block rates to effect fixed cost recovery, rendering the WNA unnecessary, she testifies that no rate design can ensure complete fixed cost recovery. (Tr. at 807-808)

Ms. Campbell further testifies that CEUG's proposal to change the WNA to tie variations in customer usage back to pro forma levels may have some merit as a way to address current reductions in customer usage. She also notes, however, that the proposal would discourage AWG from extending new service, because AWG would not receive additional revenues for new customers. (Tr. at 808-809) Additionally, Ms. Campbell notes that the adjustment clauses under Commission policy are designed to address only those circumstances outside the utility's control, with weather as the only component under which the WNA meets this requirement. (Tr. at 809)

In responding to Mr. Tinsley's recommendation to place the B-3, B-4, and B-5 customers under the WNA, Ms. Campbell testifies that these rate class exhibit very little sensitivity to weather and, as such, AWG continues to concur with Staff that they be exempt from the tariff, a recommendation shared by Mr. John. (Tr. at 810, 1120-1121, 1477) Mr. Swaim acknowledges that including B-3 customers under the WNA may be appropriate; however, he also testifies that a detailed study of customers in this class is needed to determine which are weather sensitive. Therefore, Mr. Swaim recommends that AWG be ordered to perform a detailed analysis of B-3 customers to see which customers should be included under the WNA and, if appropriate, changes can be addressed in the next rate case. (Tr. at 1477)

Finally, Ms. Campbell and Mr. Swaim address CEUG's recommendation to remove from exemption the cotton gin and grain drying customers. Ms. Campbell testifies that usage patterns of

these customers do not vary with HDD and are properly exempt from the WNA. (Tr. at 810-811, Ex. at 460) Mr. Swaim testifies that, in his recommendation for billing determinants, he did not weather adjust either set of customers, having found after review, that neither were materially impacted by weather and, consistent with his adjustment for rate setting purposes, these customers should be exempt from the WNA. (Tr. at 1478)

As discussed in the following sections, the Commission has found that CEUG's proposed rate design changes related to demand based and declining block structures are not in the public interest. Given that CEUG's recommendation to abolish the WNA is contingent upon implementation of those changes, the Commission rejects CEUG's proposal to abolish the WNA.

The Commission also finds CEUG's proposed expansion of the WNA to adjust for any usage variance from pro forma levels beyond the scope of appropriately applied automatic adjustment clauses. This proposed change to the WNA effectively fixes recovery of the entire last revenue requirement used to set commodity rates. Such a tariff not only fails to target a highly volatile material cost, but targets no single cost, allowing for set recovery of the last commodity revenue requirement irrespective of actual costs. As such, it fails for consideration for automatic treatment. Additionally, its effect mitigates the benefits now allowed by the lag between rate filings, including load growth revenues and efficiency incentives. One effect of such an adjustment would, as noted by Ms. Campbell, discourage customer growth as changes in usage are adjusted back to pro forma levels. With suppressed customer growth, there will also be a loss of the efficiencies that growth can provide by spreading fixed costs over a larger number of customers. Additionally, this will create an incentive to file for increases in rates because any increases in cost would not be

balanced by the increases in revenues from new customers. In addition, the Commission notes also that, if revenue losses occur from reduced deliveries, those lost revenues will automatically be collected from all other customers. This will guarantee AWG recovery of the last commodity revenue requirement used to set its non-gas rates. That recovery will occur irrespective of the reasons for the reduction in deliveries or of any corresponding cost decreases that reduction may have provided. The Commission finds that the results of Mr. Tinsley's proposal, in either scenario, are not reasonable nor in the public interest.

The Commission also finds CEUG's proposed amendments, adding all rate classes to and eliminating certain customer exemptions from the WNA, unnecessary as the changes proposed reflect no material benefit. The Commission finds that the impact of weather on rate classes B-4 and B-5 and the cotton ginning and grain drying customers is, as shown in Ms. Campbell's testimony, not material and coverage under the WNA is not necessary. Although B-3 customers currently are subject to a weather adjustment, Mr. Swaim's proposal to isolate and measure the impact of weather on these customers before covering them under the WNA is prudent and, therefore, his recommendation is approved. Mr. Tinsley's proposal to include in the WNA a written standard outlining qualification for exemption is unnecessary given the few customers to which it will apply. The Commission therefore finds, in view of the limited impact, there is no reason to expand the tariff to other rate classes or to those customers currently exempt and there is no need to incorporate exemption standards in the tariff. However, in view of Mr. Swain's testimony, the Commission orders AWG to track usage patterns of its B-3 customers so that the issue of whether any of these customers should be covered by the tariff may be addressed in AWG's next rate filing.

Finally, the Commission rejects CEUG's proposal to establish separate commodity rates, containing no variable costs, for use exclusively in the WNA. In this regard, while there will be an upward adjustment to the variable costs in the rate when weather is warmer than normal, there will also be a downward adjustment to those same variable costs when weather is colder than normal. The limited benefits such precision will add are outweighed by the additional complication to the calculation of the cost of service and complication and confusion added to the resulting tariff. The Commission, therefore, finds that no change to the make-up of the base rates used in the WNA is appropriate and rejects CEUG's proposal in this regard.

B. Transportation Rates/Demand Based, Sales Rates/Declining Block, Separate Rates for Transportation and Sales

CEUG recommends that the Commission order separation of sales and transportation rates, with new and different rate structures applied to each. CEUG recommends, first, that transportation rates be designed with all demand costs collected in the demand.[23] CEUG also recommends that declining block rates be designed for sales customers and that the demand costs that are currently included in the commodity rate now be recovered in base consumption. For transportation customers, all variable costs will be collected in the commodity rate and variable costs for sales customers will be collected in the remaining blocks. (Tr. at 1217-1218, 1325-1326)

CEUG witness Tinsley explains that he is recommending declining block rates for sales customers given that most of these customers do not have the meters necessary to use demand

[23] CEUG Witness Tinsley, in his testimony on cost classification and allocation, recommended that all fixed costs should be classified as demand and allocated on that basis. It is assumed that it is his preference here to have all such fixed costs already classified as demand. His actual recommendation as to rate design, however, is to include all fixed costs which are classified as demand in the demand rate. It can be inferred that, to the extent a fixed cost has been classified as commodity, under his proposed demand rate structure that fixed cost will be recovered in the commodity rate.

billing. (Tr. at 1218) Mr. Tinsley testifies that these rate structures will minimize intra-class subsidies, reduce incentive for high-load factor customers to bypass, reduce working capital needs and resulting rate base, encourage natural gas cooling, reduce potential utility under- and over-recovery of fixed costs, send more accurate price signals, and provide an incentive to reduce consumption during peak periods. (Tr. at 1218-1219) In addition, Mr. Tinsley asserts that separate rate structures for sales customers and transportation customers minimizes the potential for subsidization given cost of service differences for accounts receivable, storage plant production plant, storage gas, and pooling services. (Tr. at 1219) Mr. Tinsley also notes that, although there are some customers in the business classes which do not have the metering capability to use demand billing, AWG has daily flow information on all transportation customers. Therefore, Mr. Tinsley recommends that demand billing be implemented for those customers in the case. (Tr. at 1323-1329)

Ms. Campbell testifies that demand billing is essentially the norm in the electric industry, given the metering technology which can accurately measure the electric customers' monthly maximum demand. Further, she states that, because technology has improved in gas metering, AWG can now measure daily flow information for all of its B-5 customers and all but 4 of it B-4 customers, with some of that information available for its B-3 customers. She testifies further that monthly demand must be measured in order to design a demand based rate. Further, she states that these demand billing determinants have not yet been measured and analyzed and no design for that type of rate was made in this filing. Additionally, she testifies that any change in rates should be tested for customer impact, as required per Schedule H-3. She notes that adoption of a declining

block rate would result in low usage customers absorbing a greater rate increase than those with greater usage. (Tr. 805-806)

Although acknowledging that customers providing daily load information will receive a correct price using a demand based rate, Ms. Campbell also recommends that these rate design changes not be effected in this proceeding. (Tr. at 805-806) Ms. Campbell acknowledges that separate rates for transportation customers could be set for customers in each rate class, with a savings for those customers. However, she also testifies that separate rates would put AWG at risk for recovery of its revenue requirement. And, although Mr. Tinsley purports that the rate design change would provide offsetting cost savings to AWG, he fails to quantify them. Finally, Ms. Campbell notes that, should customers be allowed to switch between services, there would be an additional administrative burden to AWG. (Tr. at 806-807) Ms. Campbell recommends that, for the next rate filing, AWG assess the possibility and evaluate the customer impact of implementing a three part rate design for B-4 and B-5 customers, with a demand, customer, and commodity charge. (Tr. at 807)

Staff witness Green notes the lack of analysis performed to date and concurs with Ms. Campbell's conclusion that, prior to any rate structure changes, a full customer impact study should be done, something which Mr. Tinsley did not provide in conjunction with his recommendation. Ms. Green also concurs with Ms. Campbell that setting separate rates for transportation and sales customers is not appropriate absent a complete analysis of the costs and revenues associated with the separate services, an analysis which has not been completed in this proceeding. (Tr. at 1560-1561)

NWAGC witness John also recommends no rate design changes, given the lack of data and lack of analysis. He notes the lack of detail from Mr. Tinsley regarding the source of the demand billing determinants, the lack of evidence as to the customer impact, both intra-class and interclass, and Mr. Tinsley's lack of specifics regarding the implementation of declining block billing and the impact that rate structure would have on customers. (Tr. at 1120-1123) Mr. John also disagrees with Mr. Tinsley's assertion that these two rate designs will minimize intra-class subsidization of low load factor customers by high low factor customers. He testifies that Mr. Tinsley fails to provide threshold levels for his block rates, which makes it impossible to measure the impact on individual customers. Further, he also points out possible intraclass inequities given that, under declining block rates, low load factor customers with high usage may experience reduced rates while high load factor customers with low usage would experience increases. (Tr. at 1122-1123)

The Commission finds CEUG's recommendation to substantially change the overall design of business class rates both for transportation customers and for sales customers premature. The proposal lacks supporting data and nothing in the record reflects the impact to rates or the bills of customers in each class. The Commission finds that, although almost all customers in the B-4 and B-5 class have meters which lend themselves to demand billing, such is not the case for those transportation customers in the B-3 class, rendering it impossible to set a demand rate for those customers. The Commission finds that the purported benefits of these rate designs proposed by CEUG's are wholly unsubstantiated. Absent an understanding of how these two rate designs could realign the rates and bills of customers now served under the current structure, the Commission cannot make a finding that the resulting rates from those designs would be just and reasonable. The

Commission, therefore, finds that the current rate design for transportation customers and sales customers should not be changed to demand and block billing, respectively.

The Commission finds that CEUG's underlying proposal to set rates separately for transportation customers and for sales customers is premature. The Commission notes that CEUG fails to quantify, under any rate design, the impact this change will have either on AWG or on the customers under the services. Mr. Tinsley also fails to address any administrative costs which may occur due to customer switching. The Commission finds, therefore, that the transportation rate should continue to be based on the non-gas rate for sales customers.

However, the Commission orders AWG to begin to keep the data necessary to address CEUG's proposed rate design changes, including providing separate rates for sales customers and transportation customers, and be prepared to provide at their next rate filing the analysis necessary to measure the impact of each on customers in the various classes.

C. Standby Service

CEUG witness Tinsley recommends that, for purposes of clarification within the filed tariffs, the Term "Standby Service" be defined. (Tr. at 1222) The parties to the docket appear to agree that a definition is appropriate and made efforts during the proceeding to come to an agreement. However, at this time no agreed-upon amendment to the tariff has been filed. Therefore, the Commission approves the tariff language without the proposed definition. However, the Commission directs the parties to continue discussions to reach an agreement with regard to that definition. Upon consensus, AWG is ordered to file the appropriate amendment to its tariffs.

New Tariff/Guidelines

A set of guidelines to offer a new service and a new rider have been proposed for approval and remain in dispute. The issues disputed relate to *Master Metering* and *Combined Billing* and the *Rate Evaluation Plan* ("REP").

A. Master Metering and Combined Billing

A recommendation by CEUG witness Tinsley for the establishment of a consistent policy to provide service for *Master Metering* and *Combined Billing* customers (Tr. at 1236) remains in dispute. Mr. Tinsley recommends that the Commission compel AWG to adopt the guidelines for master metering and combined billing which he proposes. (Tr. at 1236) One of the provisions of the Stipulation and Agreement approved in Docket No. 02-227-U ("Stipulation") required "Staff to facilitate a meeting including Staff, Intervenors, and the three gas distribution companies for the purpose of developing a uniform master metering and combined billing policy. The meeting will begin by January 1, 2004, with an attempt to complete a policy by April 1, 2004. Any policy adopted will be consistent with the General Service Rules, Rule 5.20." (Tr. at 1264) Mr. Tinsley contends that, because no final agreement was reached and presented to the Commission, the parties have failed to comply with the Stipulation. (Tr. at 1264-1265)

AWG witness Gunter contends that, under the correct interpretation of the Stipulation, the parties have complied with its requirements. It is his contention that the Stipulation required only that the parties meet and try to work out a Master Metering/Combined Billing Policy and that such a policy would be in compliance with General Service Rule 5.20, and that the Stipulation did not require that the parties reach agreement. Mr. Gunter and Staff witness Booth both contend that the

required meetings took place, although no policy was adopted. (Tr. at 943-944, 1619-1620) Mr. Gunter and Mr. Booth recommend that a more appropriate forum in which to address these proposed service offerings and guidelines would be a generic proceeding. (Tr. at 944, 1620)

In this regard, Mr. Booth testifies Staff continues to have concerns that costs will be shifted to other customers and rate classes if CEUG's proposal is adopted, even with an appropriate payback period for costs related to customer switching. (Tr. at 1620-1621) Mr. Gunter recommends a 3-year payback period as appropriate. (Tr. at 944-945) Mr. Tinsley testifies that, because the "economic viability of combined billing is highly sensitive to rate design and customer charge," and, given that all three gas companies have filed for changes in rates, it is both more appropriate and more timely to address these service changes as part of this current rate proceeding. (Tr. at 1265-1266) In addition, Mr. Tinsley testifies that the 3-year payback to determine economic viability for converting customers is actually closer to 4.5 years, once adjusted to pre-tax impact and that, in view of this and although he had originally recommended a payback period of 6.3, he would now recommend only 5 years for payback. (Tr. at 1266-1267)

The Commission finds that a generic rulemaking proceeding should be established to address this issue. Given the potential for cost shifting and the need to establish a payback period which will be neither too restrictive, rendering the offer of this service meaningless, or too generous, resulting in subsidization of an uneconomic alternative, it is incumbent upon the Commission to address this issue in a generic docket in which a more thorough review of the service offer impact on multiple parties can be considered. The Commission, therefore, finds that a generic proceeding

should be established and directs Staff to file, within 45 days, a proposed procedural schedule to address this proposed change to gas service.

B. Rate Evaluation Plan

AWG proposes to supplant the current general rate case procedure with a streamlined and limited annual procedure, which it has styled the Rate Evaluation Plan, or REP. The REP continues to be supported by AWG and CEUG, subject to certain modifications, and opposed by Staff, the AG, and the NWAGC.

AWG witness Gunter testifies that the Company seeks approval of the REP because it will allow streamlined annual filings that will adjust the rates either up or down, matching current costs with rates and allowing stockholders a better opportunity to earn their allowed rate of return. (Tr. at 896) Mr. Gunter asserts that, under the current procedures and time-line for establishing rates, it is likely that any rates just established will not recover the utility's costs within a few months of being in place. (Tr. at 898) Mr. Gunter states that the REP will simulate the current rate case process using rate base, expenses and rate of return to calculate revenue requirement which could result in either an increase or a decrease[24] in rates. (Tr. at 897)

The REP will be based on a test year of actual data, ending each April 30, with pro forma adjustments allowed through the adjusted test year, ending in the following year on April 30. (Tr. at 899) AWG will file each year on August 1 to be effective November 1 and Staff will have until September 15 to object to any part of the filing. (Tr. at 903) The REP will differ in that it will

[24]Under the REP, AWG will be allowed an increase only to the extent that its earned return on equity falls more than 50 basis points below its allowed equity return and will be required to reduce its rates only to the extent that same return exceeds by 50 basis points its allowed equity return. (Tr. 901-902)

require no application, will use a range of currently-established equity returns,[25] outside of which annual rate changes will be allowed, will only include pro forma adjustments to certain accounts,[26] and will require no cost of service, with any excess or deficiency allocated to rate class based on the last approved revenue requirement by class and, once allocated, be divided by the class billing determinants to be added or subtracted from the current rate. (Tr. at 898-899) According to Mr. Gunter, adoption of the REP will make the ratemaking process more efficient and effective, extend the time between costly rate cases, help the Commission balance interests of ratepayers and stockholders by improving fairness of AWG rates and allowing each to share in the benefits of greater efficiency, cost reductions, and increased revenues, facilitate conservation, levelize Staff workload, and improve communications between the Commission and AWG. (Tr. at 904-907)

Responding to criticism by Staff, NWAGC and CEUG witnesses, Mr. Gunter testifies that AWG's proposal's purpose is simply to streamline the current process which, by its requirement to have a rate case each five years, will provide a better rate making mechanism. (Tr. at 920) He also testifies that the REP is not the type of clause to which criteria to measure the need for an automatic adjustment should be applied and, further, that such criteria are not required by either rule or statute, but are simply guidelines against which the Commission has measured other clauses in the past.

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[25]The allowed return on common equity ("ARCE") will be established each year using the same methodology as that which was used and approved in the last general rate filing and once established the allowed range of equity returns, 50 basis points above and 50 basis points below, will be set. (Tr. 901)

[26]Proposed adjustments allowed will include: rate base adjustments for pro forma plant which will be placed in service through the end of the adjusted test year and related accumulated depreciation; revenue adjustments to eliminate cost of gas revenue, adjustments for customer growth and for weather, annualize REP revenues, and incorporate changes in Ccf use by customer; and, expense adjustments to eliminate certain non-utility expenses, update payroll and payroll taxes for raises, new hires, and retirements, update pension costs, and update employee medical insurance costs. (Tr. 899-900)

(Tr. at 920) Mr. Gunter notes that, unlike automatic clauses, such as the cost of gas clause, the REP will be reviewed prior to implementation, will allow regulatory review for disputed items, and will not allow an increase absent AWG's earned equity return falling below 50 basis points of its Allowed Return on Common Equity or ARCE. (Tr. at 921)

Under the proposed process, Mr. Gunter states that Staff would require less time for review and, having already conducted a full rate case, Staff should be fully informed of AWG's financial condition, will be required to review only the major adjustments allowed under the tariff, and will benefit by the ongoing familiarity with AWG which annual REP filings would provide. He testifies further that, to the extent that other utilities also put in place similar mechanisms, the Commission could stagger such filings to allow Staff to best utilize its time and resources. (Tr. at 921-922)

In response to NWAGC witness John's concerns that the REP fails to include all elements of revenue requirement, Mr. Gunter testifies that, in order to provide the streamline process, the REP excludes some elements but does include those items which will have a material impact. Mr. Gunter states that the Company is open to suggestions as to any other items which the parties may deem likely to materially affect the resulting revenue requirement. (Tr. at 923) Mr. Gunter also responds to CEUG witness Tinsley's concerns regarding the tariff's provisions which allow only Staff as part of the review process. Absent that limitation, Mr. Gunter states that the process will not work in the streamlined manner for which it is designed and Staff's review and ability to object, with such objections slowing the process, should ensure that AWG does not make inappropriate requests. (Tr. at 924-925)

Mr. Gunter also testifies that the equity range provision of the REP will provide AWG the proper incentive to control its costs, given that it will be allowed to retain earnings up to 50 basis points in excess of its ARCE and will, in turn, be required to absorb costs which reduce its earned return up to 50 basis points less than its ARCE. (Tr. at 925-926) Mr. Gunter and AWG witness Stewart testify that, in addition, none of the parties have addressed the REP's elimination of the current process's disincentive for AWG to offer beneficial conservation programs. Absent the REP process, AWG would lose substantial margins should it successfully promote conservation on its system but, with the REP, the nexus between reduced use of gas by customers and the margins allowed AWG will be eliminated, allowing conservation to bring substantial long term ratepayer benefits. (Tr. at 926-927, 226-230, 231-235) Those benefits, Mr. Stewart testifies, include general benefits such as reduced natural gas demand (Tr. at 227-228), reduced cost of gas (Tr. at 228-229), and better utility financial performance with resulting lower costs. (Tr. at 229-230)

Mr. Stewart testifies that the process should also bring direct AWG-customer benefits such as reducing a customer's total bill, eliminating delay by AWG in investing in its system, reducing peak needs using programs such as weatherization, and putting downward pressure on gas prices in the market from which AWG purchases its supply. (Tr. at 230) Mr. Stewart also testifies that, if the Commission wishes to pursue implementation of conservation by its jurisdictional utilities, it will have to use the REP or something similar, given that, under Arkansas' Energy Conservation Endorsement Act of 1977, utilities must also benefit. (Tr. at 231-232, 238-239) Mr. Stewart also rebuts Staff witness Brown's testimony calling for a reduction in the equity return should the REP be approved. Mr. Stewart testifies that no reduction in the cost of equity is needed because, absent

the REP, the current rate case process does not afford AWG an opportunity to earn its approved return, as required by the "constitutional standards" under which the Commission regulates. (Tr. at 238-239)

Staff, NWAGC, and the AG all recommend that the Commission reject the REP. Staff witness Booth testifies that, while the Commission has full authority to do so, Staff opposes implementation of the REP given that it does not appropriately balance stockholder and ratepayer interests. (Tr. at 1599-1600) Mr. Booth notes that the REP is a significant departure from current ratemaking in Arkansas and he fails to see the ratepayer benefit or public interest of having AWG increase rates to its customers from its expected 18-20 month schedule to every 12 months, with those annual rate increases subject to significantly less review. (Tr. at 1600-1601, 1609) Mr. Booth also testifies that, although AWG asserts the current rate process is a failure, AWG has not yet fully availed itself of that process. (Tr. at 1609) Nor is there, according to Mr. Booth, any enhanced incentive for "greater efficiency, cost reductions, and increased revenues" under the REP's provisions which allow AWG to keep up to 50 basis points in excess earnings or be required to absorb up to 50 basis points in under earnings, given that, under current rate treatment, AWG may keep all earnings in excess of its last approved equity return, as it also must absorb all earnings shortfalls. (Tr. at 1611)

In addition, Mr. Booth contends that the REP is essentially an automatic adjustment clause, which, he notes, fails to meet the criteria[27] for which such clauses are deemed in the public interest.

[27]The criteria usually used to measure the public interest of allowing implementation of automatic adjustment clauses are: (1) the cost subject to automatic adjustment is a significant portion of the utility's operating costs; (2) the cost exhibits extreme volatility and unpredictability, with the volatility trending either upward or downward; and, (3) the cost

Mr. Booth testifies that the REP is similar to a proposed automatic mechanism filed by Arkla in a recent docket, which the Commission rejected, and, similarly, the AWG proposed REP should also be rejected. (Tr. at 1601-1603) Mr. Booth testifies that, just from an administrative position, the Staff would oppose the REP in view of the extraordinarily limited period allowed under the tariff for Staff review and the precedent set for other utilities to ask for similar treatment. (Tr. at 1603-1604) However, should the Commission approve the REP, Staff witness Brown testifies that his current recommendation with regard to cost of equity would need revisions downward to incorporate the significant reduction in business risk the REP would afford AWG. (Tr. at 661)

Mr. Marcus testifies that the REP is too far reaching and that AWG's representation of it as a method to remove conservation disincentives is over-stated and that it should be rejected. (Tr. at 120-121)

Mr. John also recommends disapproval of the REP, testifying that, while he sees substantial benefits for AWG, he sees none for ratepayers, noting as an example that, while the REP will allow AWG to increase certain costs, it provides for none of the offsetting reductions found when all costs are considered under the current rate making process. (Tr. at 1125-1126)

Mr. Tinsley currently recommends that the Commission approve the REP, having been persuaded that it will benefit ratepayers, will appropriately streamline the rate setting process, and will aid to foster conservation and thereby lower gas costs. (Tr. at 1280-1281) Initially, however, CEUG witness Tinsley recommended disapproval based on his concerns regarding the REP's (1) lack of adequate representation by other parties, (2) disincentives to control costs, and (3)

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is outside the control of the utility's management. (Tr. at 1601-1602, 1610-1611)

guaranteed return with no commensurate performance requirements. (Tr. at 1163) Mr. Tinsley had objected to the REP, testifying that it was simply an over- or under-collection mechanism, which allowed no intervenor participation, guaranteed a return, provided no incentive to control costs, failed to consider all costs, and was not tied to any performance requirements for the utility. (Tr. at 1163-1165) His current recommendation for the REP's approval is, however, subject to (1) including all costs in the evaluation, (2) eliminating the WNA and setting demand based rates for B-4 and B-5 customers, (3) reducing equity cost given the reduced risk, (4) be open to all parties, and (5) limiting rate case filings to once in every five years. (Tr. at 1280-1281)

The Commission finds that AWG's assertions regarding its inability to "earn a constitutionally adequate return" under the current process is not supported by evidence or analysis indicating that AWG has not earned a sufficient return or has not been afforded the opportunity to earn that return. AWG, by law, may file for rate relief as often as every 10 to 11 months, but the record of AWG's rate requests indicates that it has not taken advantage of that opportunity. (Tr. at 1609) More importantly, however, the rates under which AWG provides service have been found to be just and reasonable. Once prospective rates have been established those rates are deemed just and reasonable until such time as they are changed by order of the Commission. In this proceeding AWG has failed to establish by substantial evidence that an REP is necessary to protect its rights to collect just and reasonable rates. Therefore, the REP is rejected.

Miscellaneous

The parties also remain divided with regard to the recommendation that, for AWG's next

rate case, the Company be required to file, concurrently with any total company rate proposal, proposed rates, revenue requirements, and cost of service studies for its *Northeast and Northwest* operations. The parties also remain divided with regard to the rate for *Fuel and Lost and Unaccounted for Gas* ("LUFG"), proposed monthly updates for those costs, and the treatment of this item for Order 63 service. Finally, the parties disagree on the appropriate treatment of *Transportation Balancing Revenue.*

A. Northeast and Northwest Separation

CEUG witness Tinsley initially recommended that, absent a showing of the benefits of the original consolidation, AWG be required to separate its Northeast and Northwest regions for rate purposes. Mr. Tinsley contends that AWG has never provided appropriate justification for that consolidation. Alternatively, Mr. Tinsley proposed that AWG be required to track the data necessary to file separate costs of service for each region (Tr. at 1182) and subsequently recommends that AWG, with its next rate case filing, be required to file both combined and separate costs of service for its Northeast and Northwest regions (Tr. at 1334)

As noted by AWG witness Gunter, the Commission approved, with no restrictions, the consolidation as part of a Settlement submitted by the parties in Docket No. 02-227-U (Tr. at 947) and, absent some evidence to support his contention that there is interregional subsidization (Tr. at 1290) with a material impact, which Mr. Tinsley has not provided, the Commission rejects his recommendation in this regard.

B. Fuel and Lost and Unaccounted For Gas ("LUFG") - Rate Design/Allocation

CEUG witness Tinsley recommends that AWG's allocation of fuel and LUFG charges to its retail ratepayers be changed. (Tr. at 1199) Mr. Tinsley notes that fuel and LUFG charges under its retail transportation tariff are currently set as an 'in-kind' gas delivery of 4.62% of the volumes AWG delivers to the customer. (Tr. at 1194) Additionally, he recommends that AWG's collected FERC jurisdictional charges for fuel and LUFG, charged to its FERC Order 63 customers, be used to reduce the retail Fuel and LUFG allocated cost. (Tr. at 1198) Mr. Tinsley testifies that, as was indicated in APSC Docket No. 02-024-U,[28] fuel and LUFG are independent of the level of volumes flowing through the system, arising rather from the system's characteristics, condition, and pressure. (Tr. at 1195-1196) Therefore, he recommends that fuel and LUFG charges be billed to sales and transportation customers up to a reasonable amount of actual cost (a cap set on cost), allocated to each rate class at 50% coincident peak and 50% on volumes, and collected in a separate line item from sales customers and in an 'in-kind' exchange from transportation customers. (Tr. at 1198-1199)

AWG witness Stevens testifies in response that (1) LUFG levels are based on more than just pressure,[29] (2) pressure on AWG's system varies constantly, and (3) the level of throughput directly impacts pressure and, as such, it is more appropriate to allocate these costs on a volumetric basis rather than coincident peak as Mr. Tinsley proposes. Mr. Stevens notes that allocation of LUFG and

[28]Docket No. 02-024-U was a rate filing by Arkansas Oklahoma Gas Company ("AOG") and Mr. Tinsley references the initial testimony of Russell Feingold, page 33, lines 16-17. (Tr. at 1196)

[29]Mr. Stevens lists among others: input/output measurement differences, theft of gas, cycle billing effects, and purge and pack of new gas lines during maintenance. (Tr. at 862)

fuel on coincident peak effectively allocates that cost on only .3% of fuel used in the entire year. (Tr. at 862-864) Mr. Stevens also testifies that, given the relationship of pressure to volumes, it is still appropriate to collect the costs as a percent of those volumes for transportation customers and as part of the cost of gas for sales customers. Mr. Stevens further testifies that changing billing so that these charges are reflected as a line item charge will only serve to confuse customers and should be rejected. (Tr. at 864) Nor is it appropriate, Mr. Stevens states, to set a cap on recovery of LUFG and fuel for AWG, given that AWG appropriately attends to its operations and maintenance and given that its activities in this regard are monitored by the Commission. (Tr. at 864)

The Commission finds that CEUG's proposal to capture actual costs of fuel and LUFG for recovery from sales customers as a line item is not necessary. As part of the cost of gas, actual costs for both will be recovered. The Commission also finds that CEUG's proposed allocation of a portion of these costs on coincident peak fails to properly recognize the relationship between volumetric activity, pressure, and leaks as discussed by Mr. Stevens. (Tr. at 862) Given the nexus discussed by Mr. Stevens in this regard, the Commission also finds that, for transportation tariffs, use of a factor or percent of volumes delivered to measure fuel and LUFG[30] is appropriate. The Commission notes that, other than Mr. Tinsley's proposed methodology change already rejected by the Commission, no party provides evidence in support of or recommends a change to operation of that factor or the factor itself. The Commission, therefore, approves the transportation service's fuel and LUFG factor currently in effect and as previously approved by the Commission.

[30]For transportation service, the factor is applied to delivered volumes and the transportation customer provides payment in the form of like-kind deliveries. (Tr. at 1193-1194)

3. Transportation Balancing Revenue

Remaining in dispute is the appropriate allocation of revenues related to transportation customers' imbalances. CEUG witness Tinsley recommends that "(a)ll revenues associated with imbalance penalties . . . be allocated directly to the transportation customers." (Tr. at 1214) He asserts that these "imbalance fees" are assessed to cover the cost of imbalances, not to penalize the customers, and it is therefore appropriate that these revenues be allocated back to the transportation customers. AWG witness Campbell disagrees and testifies that these charges are penalties charged to transportation customers for failing to adhere to the balancing provisions of the tariff. (Tr. at 803)

The Commission finds that Ms. Campbell's definition of these charges as penalties is correct. Based on the terms of the tariff, the charges made for over- or under-deliveries, or being out of "balance" are labeled "penalties", are administered after the fact, and increase disproportionately to increased imbalance. (Application, Tariffs, Rate Schedule 2.7, pp. 7-15) The Commission finds the terms of the tariff are, in fact, intended to discourage imbalances by applying penalties, not charging "fees." The Commission, therefore, rejects Mr. Tinsley's request to allocate these revenues directly to Transportation Customers, and approves the allocation proposed by AWG.

Conclusions

(1) Although we have rejected AWG's proposed REP within the context of this company-specific proceeding, the Commission is inclined to consider a new rate case approach that would have the effect of streamlining the existing and long-standing rate case process. Based upon the

evidence presented in this case and in previous rate cases, the Commission is not prepared to find that the REP mechanism, as proposed, is the appropriate substitute process. However, the Commission is willing to consider proposed changes to the rate case process in a generic proceeding. Also, the Commission is willing to consider in a generic proceeding a decoupling mechanism designed to encourage efficiency and conservation. Further, the Commission is willing to consider in a generic proceeding a performance-based methodology designed to allow a variable return on equity adjustment, based on utility performance, customer service and other metrics, within a reasonable equity return range.

(2) Based upon the findings set forth hereinabove, the Commission rejects the rates and charges proposed by AWG and directs it to file new rates and charges in compliance with the provisions of this order.

BY ORDER OF THE COMMISSION

This 31st day of October, 2005.

Sandra L. Hochstetter, Chairman

Daryl E. Bassett, Commissioner

Separate Opinion of Commissioner Randy Bynum

With the following exception, I concur in the foregoing opinion of my colleagues. As I did in AWG's last rate case in Docket No. 02-227-U, I am again obliged to take issue with the Commission's decision in that case to allow AWG to consolidate its Northwest ("NW") and Northeast ("NE") divisions and to implement one set of rates and tariffs for the combined divisions. Prior to that decision each of AWG's two divisions had its own set of rates and tariffs. In Docket No. 02-227-U AWG witness Gunter testified that both AWG and its ratepayers would benefit in several ways if the consolidation was approved. Although the benefits of consolidation put forth in that docket by AWG may have appeared meritorious on their face, AWG did not in that docket or in the current docket provide substantial evidence that persuades me the consolidation would be or has been beneficial for AWG's ratepayers. Accordingly, I remain concerned that the benefits asserted by AWG may not outweigh the cost impacts of consolidation on the ratepayers of the two regions.

In the present case, CEUG witness Tinsley recommends that, absent a showing of the benefits of the original consolidation, AWG be required to separate its NW and NE regions for rate purposes. Mr. Tinsley contends that AWG has never provided appropriate justification for that consolidation. Alternatively, Mr. Tinsley recommends that AWG be required to track the data necessary to file separate cost of service studies for each region; and subsequently recommends that AWG be required to file both combined and separate cost of service studies for its NW and NE regions at the time of its next general rate application. I agree with Mr. Tinsley's recommendations.

As I stated in my separate opinion in Docket No. 02-227-U, I continue to have significant concerns, not just with the obvious inter-regional subsidization of gas costs, but also with the

likelihood that the consolidation will also cause inter-regional subsidization of non-gas costs. However, given that AWG did not file separate non-gas cost of service studies and rates for the two regions in the instant case, again I have little choice but to voice my continuing concerns. In the absence of compelling evidence that consolidation has produced essentially equivalent cost savings and lower rates for the ratepayers of both regions I continue to oppose the consolidation.

Randy Bynum, Commissioner

Diana K. Wilson
Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Diana K. Wilson
Secretary of the Commission
Date 10/31/05

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 14-05-06 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

December 17, 2014

By the following Commissioners:

Arthur H. House
John W. Betkoski, III
Michael A. Caron

Lead Staff: J. Buckingham
Legal Advisor: R. Luysterborghs

DECISION

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FINAL DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Public Utilities Regulatory Authority reviews The Connecticut Light and Power Company's request for a rate increase pursuant to an Application filed on June 9, 2014 requesting an increase in revenue of $231.582 million and a 10.2% return on equity. On September 22, 2014 the request was revised to an increase in revenue of $221.098 million. The Public Utilities Regulatory Authority approves an increase in revenue of $134.076 million[1] and a base return on equity of 9.17%. This is an increase of 13.9% to distribution rates and approximately 3.3% to total rates.

In granting the revenue increases, the Public Utilities Regulatory Authority allows The Connecticut Light and Power Company sufficient funds to engage in significant capital improvements to upgrade its distribution system and modernize its systems, processes and workforce. The approved increase in revenues, the return on equity and the rate mechanisms described within this Decision, along with other determinations made in this Decision, will result in just and reasonable rates. It will provide The Connecticut Light and Power Company with sufficient revenue to maintain and operate an electric distribution system and provide a safe, adequate and reliable service to customers, while providing it an opportunity to earn a reasonable profit.

The Connecticut Light and Power Company must have the resources to be able to maintain and operate its distribution system in a manner that provides safe and reliable electric service to about 1.2 million customers in Connecticut. In addition, it must provide satisfactory customer service and provide a fair return to its investors.

The Public Utilities Regulatory Authority rejects The Connecticut Light and Power Company's request for an allowed return on equity of 10.2% and has determined that an allowed base return on equity of 9.17% is fair and reasonable. In regulating CL&P to allow a return commensurate with the current economic conditions, the Authority has determined that investors expect less of a return today than in 2010, when the return was established at 9.40%. The base allowed return on equity has been decreased by 15 basis points to 9.02% for a period of one year to reflect a penalty for The Connecticut Light and Power Company's poor performance in preparing for and restoring service from Tropical Storm Irene in 2011 and the major snowstorm that occurred in late October, 2011.

This Decision approves the proposed level of $257 million in capital spending, finding that this level of spending is necessary for safety, reliability and maintenance of the franchise. This Decision also includes past system resiliency spending in rates, which is expected to reduce the severity and frequency of outages to customers in

[1] As discussed below, the Public Utilities Regulatory Authority finds a one year return on equity penalty of 15 basis points appropriate. This penalty reduces the initial revenue increase to $129.679 million.

future weather related events, and authorizes the initiation of new resiliency programs, subject to Public Utility Regulatory Authority review and approval of spending levels in a future proceeding. Further, this Decision includes in rates the costs incurred by The Connecticut Light and Power Company in preparing for and restoring service from major storms in 2011 and 2012, as determined in previous proceedings. This Decision also approves funding for an expanded troubleshooter organization, which is expected to reduce the duration of outages at nights and on weekends.

Major reductions to revenue requirements requested by The Connecticut Light and Power Company include reductions in the requested return on equity, cash working capital of $1.869 million, $7.44 million in the requested level of depreciation expense, and $22 million in operations and maintenance expenses.

The Authority approves certain changes to The Connecticut Light and Power Company's rates and revenues. This Decision makes certain adjustments to pole attachment revenue. The Decision accepts the Company's proposed sales forecast and revenue allocation methodology as reasonable for setting rates. The Decision lowers the proposed increases in fixed charges proposed for the residential and small commercial rates. The Street Lighting rates have been unbundled into system and equipment components and the proposed LED lighting options are approved. The Authority recalculates the Company's pole attachment rates as outlined herein. This Decision also approves a revenue decoupling mechanism as outlined herein. The approved revenue requirements, revenue allocation and rate design changes discussed above will result in an increase of approximately $7.12 per month for the average residential customer bill.

B. BACKGROUND OF PROCEEDING

The Connecticut Light and Power Company (CL&P or Company) is a public service company within the meaning of §16-1 of the General Statutes of Connecticut (Conn. Gen. Stat.). CL&P is a subsidiary of Northeast Utilities (NU). The Company currently provides electric service in 149 towns and cities in Connecticut. Application, p. 3.

By letter dated May 9, 2014, CL&P provided notice of its intention to file an application for approval to amend its rate schedules (Application) to the Public Utilities Regulatory Authority (Authority or PURA), the Governor of the State of Connecticut, the Chief Executive Officer of every municipality located within its franchise area, the Office of Consumer Counsel (OCC) and the Office of the Attorney General (AG). In addition, the Company requested waiver of certain provisions of the Standard Filing Requirements (SFRs).

By letter dated May 20, 2014, the Authority granted the Company's request for waiver of certain portions of the SFRs for Large Public Utility Companies. The Authority also approved the Company's request for allowance to submit data required in Schedules F-1.0 through F-9.0 on a calendar year basis reflecting the 12-month period ending December 31, 2013.

By Application dated June 9, 2014, CL&P requested to amend its existing rate schedules pursuant to Conn. Gen. Stat. §§16-19 and 16-19e and §§16-1-46 and 16-1-53 *et seq.* of the Regulations of Connecticut State Agencies (Conn. Agencies Regs.), and the SFRs. The Company indicated that this increase is necessary to address a distribution operating deficiency of $116.7 million, and to implement recovery of $89.5 million of storm costs and $25.3 million of system resiliency costs approved by the Authority in prior dockets.[2] In total, the Company proposed rates designed to recover additional costs of $221.098 million during the period from December 1, 2014 - November 30, 2015 (Rate Year). Application, pp. 2 and 3.

C. CONDUCT OF PROCEEDING

On June 3, 2014, pursuant to Conn. Gen. Stat. §16-19(a), the PURA notified all admitted parties and intervenors that it would extend the 150-day period, directed by Conn. Gen. Stat. §16-19(a), to render a final Decision in this docket by 30 additional days.

By Notice of Audit dated June 13, 2014, the Authority conducted an audit of CL&P's books and records at the Company's offices located at 107 Selden Street, Berlin, Connecticut, 06037, beginning on June 23, 2014. The Authority conducted a separate audit of the Company's rates and revenues at the same location on July 10, 2014, pursuant to a Notice of Audit dated July 2, 2014.

Pursuant to a Notice of Pre-Hearing Conference dated June 3, 2014, the Authority conducted a Pre-Hearing Conference on June 19, 2014, to discuss procedural issues with all admitted parties and intervenors, at the Authority's offices located at Ten Franklin Square, New Britain, CT, 06051. At the Prehearing Conference, the Authority and all Parties agreed that the schedule would be extended to provide for a Final Decision by December 17, 2014, with rates to go into effect on December 1, 2014.

By Notice of Hearing dated July 21, 2014, pursuant to Conn. Gen. Stat. §§16-11, 16-19 and 16-19e, the Authority conducted daytime hearing sessions at its offices on August 27 and 28, 2014 and September 2, 3, 4, 5, 8, 9, 10, 11 and 12, 2014. The hearings were continued to September 24 and 25, 2014.

In addition, the Authority held evening sessions solely for the purpose of receiving public comments. The hearings commenced at 6:30 p.m. on the following dates, at the following locations: August 27, 2014, at the Authority's offices; August 28, 2014, at the Stamford Government Center, 888 Washington Boulevard, Stamford, Connecticut; and September 3, 2014, at New London City Hall, 181 State Street, New London, Connecticut.

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[2] In the Decision dated March 12, 2014 in Docket No. 13-03-23, Petition of The Connecticut Light and Power Company for Approval to Recover Its 2011-2012 Major Storm Costs, the Authority approved cost recovery of certain major storm related costs. In its Decision dated January 16, 2013 in Docket No. 12-07-06, Application of The Connecticut Light and Power Company for Approval of Its System Resiliency Plan (Resiliency Decision), the Authority approved cost recovery of costs related to system resiliency initiatives.

The Authority issued its Proposed Final Decision in this matter on December 1, 2014. All parties and intervenors were granted an opportunity to file Written Exceptions to the draft Decision and to present Oral Arguments.

D. PARTIES AND INTERVENORS

The Authority designated The Connecticut Light and Power Company, 107 Selden Street, Berlin, Connecticut 06037; Office of Consumer Counsel, Ten Franklin Square, New Britain, Connecticut 06051; and Department of Energy and Environmental Protection Commissioner Robert F. Klee, 79 Elm Street, Hartford, CT 06106-5127 as Parties to this proceeding.

Intervenor status was granted to: Office of the Attorney General; Environment Northeast; Cablevision of Connecticut, LP; International Brotherhood of Electrical Workers; New England Cable and Telecommunications Association, Inc.; Fiber Technology Networks, LLC; and Wal-Mart Stores, Inc.

E. PUBLIC COMMENT

The Authority conducted evening public comment hearings within the CL&P service territory for the purpose of receiving comments from the general public concerning the Application. CL&P's notice to customers regarding the hearings, submitted by the Company on June 16, 2014, was approved by the Authority on June 17, 2014.

A total of 203 persons attended the public comment hearings and 64 of those persons provided testimony to the Authority. U.S. Senator Richard Blumenthal urged the Authority to consider how a 59% increase in the residential customer service charge would affect the poor and elderly. Tr. 8/27/14, pp. 251-253. State Representative Lonnie Reed stated that CL&P's proposed rate increase seemed to be working at cross purposes to public policy, which supports a focus on conservation and renewable energy. Id., pp. 254-257.

Public comments mirrored those provided by the public officials. Residential customers were particularly opposed to the proposed $9.50 increase in the customer service charge. Tr. 8/27/14, pp. 263-265, pp. 269-277 and pp. 284-291; Tr. 8/28/14, pp. 563-565 and pp. 582-591; Tr. 9/3/14, pp. 1099-1118 and pp. 1134-1138. Overall, most Connecticut residents and businesses that spoke or submitted written comment were not supportive of CL&P's Application. Many cited the state's current economic condition and the financial impact of a rate increase.

Several organizations spoke in favor of CL&P's Application, stating that reliability of electric service was very important. The Windham Region Chamber of Commerce noted improvements in CL&P's quality of communications and coordination of staff and technology than it had presented before the last rate case. Tr. 9/3/14, pp. 1094-1098.

The Authority also received approximately 2,000 letters and emails regarding the Application. There were approximately 25 letters in support of the Application; however,

nearly all of the persons who wrote opposed CL&P's rate increase request, stating reasons similar to those offered at the evening public hearings.

II. AUTHORITY ANALYSIS

A. TEST YEAR / RATE YEAR

It is the practice of the Authority in utility rate cases to establish rates prospectively upon review of a historical Test Year. Revenues and certain expenses were adjusted for known changes or to reflect a normalized, annualized test year, known as the pro forma test year. In this case, the Company used the operating results for the 12 months ending December 31, 2013, as its Test Year. Schedule A-1.0. The Authority, with these adjustments, accepts this time period as the Test Year. The Rate Year is the period from December 1, 2014 to November 30, 2015, as proposed by the Company.

B. RATE BASE

1. Capital Expenditures

CL&P's proposed capital expenditures for the Rate Year are as follows:

Table 1

Proposed Capital Program

Year	Category of Capital Expenditure	Amount (in millions)	Rate Component for Recovery in 2015
2015	Traditional Capital Program	$257	Distribution Rate
2015	Pre-Approved System Resiliency Plan	$52	Distribution Rate
2015	New System Resiliency Programs	$44	NBFMCC
Total		**$353**	

Bowes PFT, p. 11.

The Traditional Capital Program consists of expenditures for programs that address routine infrastructure issues such as those necessary to supply new customer load, meet peak loads, meet basic business requirements, meet regulatory commitments, and reliability related projects. The Pre-Approved System Resiliency Plan consists of system resiliency expenditures for programs that were approved in the Resiliency Decision, and whose recovery was allowed through the Non-Bypassable Federally Mandated Congestion Charge (NBFMCC) until the following rate proceeding. The New System Resiliency Programs are system resiliency expenditures for programs that were not approved in the Resiliency Decision, which the Company contended would have a long-term impact on customer reliability. The New System Resiliency Programs expenditures would not be included in rates. Rather, the Company requested that the Authority authorize them subject to a future reopening of Docket No. 12-07-06 to review their costs and authorize recovery through the NBFMCC.

a. Traditional Capital Program

CL&P stated that it proposed to spend $257 million on its Traditional Capital Program in the Rate Year, and noted that it spent $268 million for the same types of programs in 2013. At the requested level of spending, the Company expects to be able to improve day-to-day reliability while decreasing capital spending due to the combined effect of the following three factors: 1) efficiencies achieved through reorganization and consolidation initiatives; 2) improvements achieved as a byproduct of system resiliency programs; and 3) implementation of the new troubleshooter organization. Bowes PFT, pp. 11 and 12.

CL&P's Traditional Capital Program, disaggregated by focus area, is shown in the table below.

Table 2

CL&P Capital Program 2013-2015
($ in Millions)

Focus Area	Description	2013 Actual	2014 Forecast	2015 Forecast
New Customer	Customer-driven projects	48.6	38.5	40.5
Peak Capacity	Distribution/substation capacity projects	24.4	22.3	21.1
Basic Business	Equipment failures/facilities/IT/vehicles/ environmental/lighting/miscellaneous	106.5	109.8	114.9
Regulatory	Grounding/double poles/high-over-low voltage/cable replacement/worst circuits	25.5	20.1	12.0
Reliability	Enhanced trimming/distribution line reliability/substation reliability/network reliability	66.7	65	68.2

Response to Interrogatory EN-2.

No party or intervenor opposed any Traditional Capital Program specific capital expenditure or project to be added to plant-in-service.

The OCC stated that data provided by CL&P shows that actual plant additions during the years 2008 through 2013 were 4.21% lower than budgeted. According to the OCC, forecasted plant additions should be reduced by this amount to determine the appropriate level to be included in rates. The OCC also criticized CL&P for providing a forecast for plant-in-service but basing its analyses on capital expenditures. Finally, the OCC questioned whether the Company's Board of Directors authorized the expenditures, and asserted that unsuccessful efforts to compel CL&P to produce a capital expenditure approval policy casts doubt on the Company's capital plans. OCC Brief, pp. 39-44.

CL&P stated that capital expenditures do not equate to plant-in-service due to timing differences. For example, large multi-year projects involve capital expenditures each year, but are not included in plant-in-service until the projects are complete. Furthermore, during the period 2008-2013, CL&P spent the capital expenditures forecasted in prior rate cases. Finally, CL&P observed that the OCC selectively included 2008 and 2009 in its comparative analysis, when the variances were

abnormally large due to the unforeseen severe global recession, which reduced capital deployment. When those years are removed, plant-in-service was 99.86% of the Company's budgeted level, or almost precisely equal to forecast. CL&P Joint Rebuttal Testimony of Kenneth Bowes and Jeffrey Michelson, pp. 4-7.

The Authority examined the issue of plant-in-service forecasting for the purpose of adjustments to rate base in its Decision dated February 4, 2006 in Docket No. 05-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges (UI Decision). In that Decision, the Authority found as follows:

> The Department believes construction programs should be analyzed by examining the needs the programs are intended to address, and the reasonableness of the solutions to those needs. Comparisons to historicals are useful to assist in determining whether the total expenditures are within a range of reasonableness, but even if projected expenditures vastly exceed historicals, to rationally analyze a company's proposed expenditures the Department must analyze them on a project-specific basis. Therefore, any adjustments based on gross comparisons to historical levels alone are not sufficient. Regarding the OCC's assertion that projected plant additions are much higher than historical, the Department notes that the plant additions are netted against retirements. Because additions can vary largely from one year to another, and because large amounts of retirements can offset the additions leading to a low net number, it is not valid to compare net plant additions between years… The Department therefore believes that comparisons to historical additions are not a valid determinant of future plant additions.
>
> UI Decision, p. 24.

The Authority reiterates these findings, as the premises have not changed. Although it is appropriate to consider plant additions in forecasting, a plant addition forecast should be based on capital expenditures. The Authority closely examined capital expenditures in this proceeding. Furthermore, in the past several CL&P rate proceedings, the Authority has required the Company to report on capital expenditure variances each year, which allows the PURA to closely monitor spending. Over the three years since CL&P's last rate proceeding in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules (2009 CL&P Rate Case), CL&P's actual and forecasted capital expenditures were as follows.

Table 3

CL&P Capital Expenditures 2010-2012
($ in millions)

	Forecast	Actual
2010	310.8	305.4
2011	332.6	338.5
2012	315.4	312.8

Decision dated June 30, 2010 in Docket No. 09-12-05 (2009 CL&P Rate Case Decision); Order No. 2 Compliance Filings dated March 31, 2011, March 30, 2012 and March 26, 2013.

Total capital spending over the years 2010-2012 was $956.7 million, which is within approximately 0.2% of the 2009 CL&P Rate Case forecast amount of $958.8 million. This historically accurate capital spending forecast gives high confidence to CL&P's planned capital spending presented in this case. Therefore, the Authority will not make any adjustment to CL&P's proposed capital spending/plant-in-service on the basis proposed by the OCC.

The Authority reviewed CL&P's proposed capital program and concludes that the expenditures are reasonable and necessary for safety, reliability, and maintenance of the franchise.

The Company will be required to report on its capital spending as follows: by November 30 of 2015, 2016 and 2017, with a budget/forecast of spending by initiative or category for the following year; and by March 31 of each year 2014, 2015 and 2016 showing actual spending by initiative or category for the preceding year. These reporting requirements recognize that CL&P is required by the NSTAR merger settlement agreement,[3] to apply to the Authority for a rate proceeding in 2017; therefore, the PURA will remain apprised of capital spending and have a history of such spending in its records when the 2017 application is made. The Authority recognizes that plans may change for good reason over the next two years. Accordingly, if the budgeted amount for any initiative or category changes by more than 10% from that represented in this proceeding and as modified by the Authority, the Company must provide an explanation in the annual budget report due each November 30. Further, if actual total spending varies from budgeted spending in any year, the Company must provide an explanation in the annual spending report due March 31 of each year.

b. Pre-Approved System Resiliency Costs

The Resiliency Decision allowed the Company to flow the costs of the System Resiliency Plan through the NBFMCC until the Company's next rate case, at which time the costs would be factored into the Company revenue requirements. The Authority

[3] Approved by the Authority in its Decision dated April 2, 2013 in Docket No. 12-01-07, Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR (Merger Decision).

finds that the Company has complied with the ratemaking treatment as allowed in the Resiliency Decision in this filing. Resiliency spending, in the amount of $25.343 million, for the years 2013-2014 is added to the Company's rate base and removed from NBFMCC revenue requirements.

The Resiliency Decision allowed forecasted spending through 2017 for resiliency measures. The table below lists amounts for resiliency spending 2014-2017.

Table 4

Year	Estimated Capital	Estimated Expense	Total Spending
2014	45,000	8,000	53,000
2015	52,000	9,000	61,000
2016	68,000	9,000	77,000
2017	68,000	9,000	77,000

Resiliency Decision, p. 6.

If the PURA allows the proposed 2014-2015 resiliency expenditures in revenue requirements, the OCC recommended the Authority should order an audit of the actual costs on an annual basis to determine whether the expenditures made are supported by real cost documentation, and that the costs were prudent and specifically related to system resiliency.

The Authority finds that the orders contained within the Resiliency Decision address the OCC's concerns.

c. Proposed New System Resiliency Costs

CL&P stated that it achieved improvements in service reliability in 2013 primarily through the implementation of best practices and an enhanced vegetation management program. According to the Company, there are other initiatives that are recognized within the industry as having a significant impact on building system resiliency to the long-term benefit of customers. CL&P identified certain core initiatives that, if implemented, would have the greatest long-term impact on system resiliency, and an important secondary impact on system reliability. The Company asserted that these initiatives are necessary to modernize the system and provide its customers with the level of service that they should expect from CL&P. The Company requested authorization to start these programs, subject to a future reopening of Docket No. 12-07-06 to review and approve specific program budgets and to recover the costs of the program through the NBFMCC. None of the new system resiliency costs are included in this case. Bowes PFT, pp. 19 and 20.

CL&P's proposed new resiliency program expenditures in 2015 are as follows.

Table 5

CL&P New Resiliency Programs
($ in Millions)

Program	Description	Proposed Spending ($ millions)
Pole Integrity	Increase resiliency of utility poles	$13
System Automation/ Grid Modernization	Increase system monitoring and control capabilities	$14
Substation Security	Increase physical security of substations	$ 4
Substation Flood Mitigation	Increase the resiliency of selected substations to flood events	$ 2
Infrastructure	Address islanded substations and improve Right of Way lines	$11
Total		$44

Bowes PFT, pp. 19-33.

The OCC stated that the Company is proposing new resiliency spending totaling an additional $368.3 million over the years 2014-2019. This amount more than doubles the $300 million program approved in the Resiliency Decision, and the OCC asserted that that the Authority should wait until after 2017 when more information is known about the efficacy of the existing resiliency program. Furthermore, the OCC objects to using the NBFMCC as a collection method for any new resiliency expenditures; rather, the OCC believed a rate-based collection method should be used. OCC Brief, pp. 149-152.

The Authority shares the OCC's concern regarding the impact of the proposed spending on ratepayers; however, the Company has not requested, nor has the Authority approved, funding levels or cost recovery in this proceeding. The Company only requested Authority permission to proceed with the new resiliency programs, subject to review of proposed spending in an anticipated reopening of Docket No. 12-07-06. Because several of the new resiliency programs address known vulnerabilities in the electric distribution system, the Authority will authorize the program to go forward. However, the Company should be prepared to do so at a level of funding below the levels it is anticipating, subject to the Authority's determination in the reopened Docket No. 12-07-06 proceeding.

The Authority notes that CL&P plans to recover new resiliency spending in the NBFMCC. The NBFMCC was an appropriate vehicle for prior resiliency spending, because the spending was mandated by the NSTAR merger agreement and initiated outside of a rate proceeding. The Authority will allow NBFMCC recovery subject to the budgets approved in the reopened Docket No. 12-07-06 proceeding as a transition until the Company's next rate proceeding. After that time, resiliency spending should be included in rate base. If the Company desires to continue to recover resiliency spending outside of conventional rates, it should seek a legislative solution.

2. Accumulated Deferred Income Taxes

CL&P reported accumulated deferred income taxes (ADITs) of $655.417 million as an offset to rate base for the Test Year, $760.36 million for the proforma period ending December 31, 2014, and $819.14 million for the Rate Year. Schedule B-1.0, p. 2. The Company reported average ADITs of $789.75 million for the Rate Year. Id.

CL&P reported plant related non-FAS 109 ADITs of approximately $461.429 million, $553.453 million, $567.297 million, $674.02 million, and $658.815 million for calendar years ending December 31 in 2009, 2010, 2011, 2012 and 2013, respectively. Response to Interrogatory AC-9, Attachment 1. The Company projected ADITs of $763.758 million and $822.537 million for December 31, 2014 and 2015, respectively. Id. The 2011 ADITs balance was net of deferred taxes of $85.477 million related to the ensued net operation losses (NOL). Otherwise, the ADITs' balance as of December 31, 2011, is $652.774 ($567.297 + $85.477) million. Id. CL&P indicated that ADITs associated with NOL of $3.46 million, $30.46 million and $51.025 million are utilized in 2012, 2013 and 2014, respectively. Id.

The Authority reviewed all exhibits submitted by the Company in this proceeding regarding the average plant related ADITs proposed for the Rate Year. The Authority has several issues with the average ADITs that CL&P used to calculate the average rate base for the Rate Year as discussed below.

a. Repair Tax Deductions

Regarding the repair tax deduction (RTD) proceeding in Docket No. 13-07-06, Joint Petition of George Jepson, Attorney General for the State of Connecticut and Elin Swanson Katz, Consumer Counsel, for an Investigation into the Response of Connecticut's Public Service Companies to Certain Changes to IRS Accounting Regulations (RTD Proceeding), CL&P indicated that this proceeding rather than a generic RTD proceeding is the proper venue to review the regulatory impacts of costs incurred for repair and maintenance of tangible property. Mahoney PFT as Adopted by Michelson, p. 24. Also, the Company stated that the deferred tax liability created by the permanent RTD regulations will reverse over the same time period as the related assets capitalized on its books are depreciated, thereby reversing the deferred tax liability as the remaining book depreciation is realized. The treatment of the RTD is similar to that of any other normalized deduction for tax and regulatory purposes. Id.

In its normalized plant-related ADITs, CL&P included deferred taxes of $40.85 million in 2014 and in 2015. These levels of ADITs are based on RTD allowances of $100 million in each year. Mahoney PFT as Adopted by Michelson, p. 25; Schedules B-7.0 and WPC-3.38, p. 2. CL&P asserted that there are no additional RTD tax benefits in 2012 and 2013 because both years' tax returns showed taxable losses. Mahoney PFT as Adopted by Michelson, p. 25.

In its response to the Authority's request to quantify the RTD amounts available in 2012 and 2013 that were not deducted because of the Company's NOL positions in both years, CL&P stated that any attempt to hypothetically measure the RTD amounts for 2012 or 2013 is meaningless given its NOL positions for these years. Response to

Interrogatory AC-86; Tr. 09/25/14, pp. 2746-2748. The Company stated that its tax planning appropriately seeks to maximize the cash benefits associated with deductions, with minimum risk of audits and disallowances by the Internal Revenue Services (IRS). As a result, the Company did not adopt the RTD temporary regulations and plans to adopt the repairs deduction, using the final regulations in its 2014 tax return. Response to Interrogatory AC-86-SP01, pp. 1 and 2. Simultaneously, CL&P concurred that the benefit associated with potential deductions from 2012 and 2013 will be included in the 2014 adjustment required when its elects to adopt the final RTD regulations. CL&P stated that its 2014 tax returns would include a cumulative RTD adjustment containing amounts that would have been deducted in 2012 and 2013 and that the resulting tax benefits of the method change will be calculated and recorded in its books. Id.

While CL&P reiterated its argument about its NOL positions in 2012 and 2013, it agreed that the benefit associated with prior years, encompassing the amounts that are in question from 2012 and 2013, will be captured as part of a cumulative adjustment deduction in its 2014 tax return. Nevertheless, CL&P argued that the Authority should not make any adjustment to its proposed revenue requirement pertaining to the RTD. The Company asserted that customers are receiving the benefit associated with formal and finalized IRS tax rules and regulations. CL&P Brief, pp. 48 and 49.

The Company's argument is based on the premise that it did not adopt the RTD regulations prior to 2014 because it was in NOL positions in 2012 and 2013 and it would be risky to adopt temporary regulations that not are finalized. The Authority agrees that an earlier adoption of the temporary RTD regulations would have further increased the Company's NOL positions in 2012 and 2013. The Authority's initial inquiry was for CL&P to quantify the RTD amounts available in 2012 and 2013 regardless of whether the amounts were deducted or not. CL&P's response was that based on its tax position or liability it would be meaningless to calculate a hypothetical number for 2012 or 2013, which are tax years prior to the effective date of the finalized RTD regulations. Response to Interrogatory AC-86. Based on its tax strategy, CL&P waited until the RTD regulations were finalized to adopt and avail itself of the benefit of the RTD allowances. Effective with the adoption of the permanent RTD regulations in 2014, there are additional look-back periods for which costs incurred for repair and maintenance of tangible property can be deducted in the 2014 federal income tax return.

The Authority's position is that the Company failed to incorporate the additional deferred tax benefits for the look-back RTD periods, which included 2012 and 2013, in its estimated deferred taxes for 2014. CL&P finally agreed that its 2014 tax return would include a cumulative RTD adjustment for prior periods. CL&P stated that "When the Company adopts the Regulations for its 2014 tax year a cumulative adjustment as a result of the method change will be calculated. Any benefit from the change will be recorded by the Company. Any amounts which would have been deducted in 2012 and 2013 will be included in that cumulative adjustment in the Company's 2014 tax return." Responses to Interrogatories AC-86 and AC-86 SP01; CL&P Brief, p. 48. The Company agreed that 2012 and 2013 RTD allowances to be included in its 2014 cumulative amounts would garner additional normalization deferred tax liabilities that would be recorded on its books. However, the Company only included the deferred taxes associated with RTD allowances in 2014 and 2015 in this proceeding. It failed to include the deferred tax benefits for the 2012 and 2013 RTD expenses that would be

included in tax depreciation deductions in its 2014 tax returns as a result of the adoption of the finalized RTD regulations. The question now is what meaningful number would be reflected in the Company's 2014 tax return as the amount representing RTD expenses for the look back periods of 2012 and 2013. The Company initially stated that such figure would be hypothetically meaningless.

The Authority estimated that at a minimum, the total RTD allowances for 2012 and 2013 should be at least 50% of the amount the Company estimated for 2014 and 2015. Thus, the Authority estimated $100 ($100 x 50% x 2) million of RTD for 2012 and 2013. Consequently, the average ADIT amount is increased by $40.85 ($100 x 40.85%) million. Accordingly, the Authority will reduce Company's proposed average rate base by $40.85 million. This amount represents a reasonable amount of tax benefit for the 2012 and 2013 RTD that the Company will include in the total RTD to be deducted in its 2014 tax return.

In its Written Exceptions, CL&P stated that the Authority's determination to reduce its proposed average rate base by $40.85 million for the tax benefit of RTD is a mistake. The Authority made this determination based on the Company's testimony that any RTD amounts that would have been deducted in 2012 and 2013 will be included as part of accumulative RTD amount in its 2014 tax returns. CL&P stated that the Authority confused the principles of its re-computation of its actual tax position in 2012 assuming that the RTD would have been taken with that of the computation of the cumulative "look-back" RTD adjustment allowable under the final IRS regulations in 2014. CL&P Written Exceptions, pp. 23 and 25. According to the Company, the reported $100 million associated with the RTD in 2014 and $100 million in 2015 are not the RTD deductions for each year. The total $200 million represents the cumulative RTD adjustment for all prior years through 2013 and the estimated RTD for 2014. The Company shows the combined amount of $200 million over two years to indicate the cash flow impact of the RTD "catch-up" adjustment in addition to the actual tax accounting impact. Id., p. 26. Furthermore, CL&P stated that the cumulative one-time RTD adjustment for the look-back periods is estimated to be $178 million and that the annual RTD for 2014 is approximately $22 million. Id.

The OCC stated that the Authority's determination related to RTD look-back periods was proper and appropriately recognizes that CL&P will adopt these changes in its 2014 Federal Income Tax return. These tax changes will impact the income taxes paid for 2014 and in the Rate Year as well as ADIT balances. However, the OCC stated that the Authority did not make an adjustment to the Company's Federal income tax expenses. The OCC indicated that, because of CL&P's large annual budgeted capital expenditure associated with infrastructure replacement, a significant portion of the associated infrastructure repair and maintenance costs is likely to qualify as a deduction to its federal tax liability. According to the OCC, in between rate cases, there is the possibility the lower tax expense would increase the Company's earnings. The potential tax refund, increased federal income tax deductions and reduction of income taxes for 2014 and thereafter should be used to reduce the rate increases for the Rate Year in this proceeding. OCC Written Exceptions, pp. 40 and 41. Furthermore, the OCC stated that the RTD adjustment for the look-back periods that is based on only 50% of the Company's estimates for 2014 and 2015 is conservative and would not prevent a windfall to CL&P shareholders when the tax election is made between rate

cases. The OCC recommends that, subsequent to CL&P's compliance to Order No. 10 in this Decision, the Authority should have a limited reopener of this proceeding in 2015 to true-up the impact of reduced taxes and tax refunds associated with the new RTD regulations. Id., pp. 41 and 42.

In its Written Exceptions, the AG argued that the RTD adjustment for the look-back period is "extremely conservative" if costs related to system "hardening" for the years subsequent to Tropical Storm Irene, the October 2011 Nor'easter and Super-storm Sandy in October 2012 qualify as RTD investments. AG Written Exceptions, p. 8. Additionally, the AG indicated the actual RTD credits for the look-back periods would not be known until the Company files its 2014 tax returns. The AG suggested that the Authority should hold ratepayers harmless for any errors in RTD estimates and urged the PURA to apply the most reasonable and accurate estimates of the likely qualified RTD amounts. The AG also urged the Authority to assume that the actual qualified investments in years 2012 and 2013 are the same as the $200 million that the Company estimated for 2014 and 2015. The AG further proposed an additional average RTD deferred tax increase of $9.1 million. Finally, the AG suggested that a limited reopening of this proceeding be conducted in September 2015 to reconcile any discrepancies between its estimated RTD credits of $81.7 million and the deferred tax effect of the actual RTD amounts provided in the Company's 2014 Federal income tax return. Id., p. 9.

CL&P testified that "[A]ny amounts which would been deducted in 2012 and 2013 will be included in that cumulative adjustment in the Company's 2014 tax return." Response to Interrogatory AC-86. No information was provided in response to interrogatories, pre-filed testimony or during the hearing to suggest that the reported $100 million RTD in 2014 and $100 million in 2015 represented the total for the look-back-periods and the 2014 annual amounts. The first time CL&P presented this information was in its Written Exceptions. Also, there was no exhibit or testimony in this proceeding that supports the derivations of the total prior periods RTD of $178 million and 2014 annual amount of $22 million that CL&P claimed in its Written Exceptions.

It is important to make the correct determination regarding the appropriate amount of ADIT, including the estimated 2014 RTD amounts, in order to calculate CL&P's allowed rate base. The Authority is concerned withthe discrepancy between the evidence and analysis in the record and CL&P's representations offered in its Written Exceptions. The Authority concludes that it is necessary to reopen this proceeding for the purpose of ensuring that the amount of ADIT is properly calculated. In the reopened proceeding, the Authority will receive evidence on the issue of whether the reported $100 million RTD in 2014 and $100 million in 2015 in total represent the total for the look-back-periods and the 2014 annual amounts. The reopened proceeding will afford all parties and intervenors an opportunity to properly review this new evidence, the potential revenue requirement impact of the new evidence and related issues.

In the meantime, the Company is directed to track and create a regulatory asset for the revenue impact of the RTD adjustment based on its proposal. The Authority will true-up the Company's estimated revenue impact to reflect the proper RTD estimates for 2014 that will be determined in the reopener. Additionally, the Authority will reopen

this proceeding for the limited purpose of reconciling the estimated RTD allowed in the initial reopener to the actual amount reported in the Company's 2014 Federal income returns submitted as a compliance filing in this docket.

b. Account 28200 True-Up Adjustments

Unlike other periods with substantial year-over-year increases, the Authority noticed a significant decrease in the ADITs balance in Account 28200 as of December 31, 2013, as compared to the December 31, 2012 balance. The Authority identified and questioned the August 2013 adjustment to reduce the ADITs balance in this account by $124,742,248. Response to Interrogatory AC-128, Attachment 1, Revision 1, p. 33. The Company stated that the August 2013 adjustment, which reduced the deferred tax balance in Account 28200, is related to a true-up adjustment made in its 2012 tax returns and subsequently recorded in its accounting books in August 2013. Late Filed Exhibit Nos. 78 and 79. Specifically, during the course of a year, CL&P books deferred taxes based on a budget projection and such budget projections make certain assumptions. Those assumptions could include any number of different items.

At the end of the year, the Company prepares and files its corporate income tax and then trues up to the corporate income tax at the actual level. The book balance in the 28200 Account at the end of the year should incorporate the actual amount that is reflective of the Company's tax filings. Issues that could cause differences between projected and actual amounts can be anything. CL&P testified that its projected tax deductions for items such as storm activity, bonus depreciation, and repairs may not have occurred for some reason or because some other items on an actual basis precluded them from occurring. So the Company's actual tax return overrules its projections and CL&P corrects to the actual tax return. CL&P averred that it made an adjustment in its 2012 tax return that makes the true-up adjustments to its accounting books necessary. As such, the Company made a $124.742 million reduction to the deferred taxes in August 2013 in Account 28200 which represents a subsequent true-up of estimates that CL&P made during 2012 based on an adjustment in its 2012 tax return. Tr. 09/25/14, pp. 2731-2741.

In its Brief, the Company stated that the amounts in Account 28200 as of December 31, 2012, were estimated based on recognition of transactions related to plant asset retirements, additions and basis adjustments, and the expected deductions under the tax law related to those assets. CL&P stated that its computation of depreciation expense deductions for tax purposes assumed a relatively shorter retirement schedule for certain asset categories. A shorter retirement schedule increases the deduction for depreciation expense for a particular calendar period. In July 2013, when the Company was preparing to file its 2012 federal tax return, it was clear that the combination of actual operating income, increased system investment and the existence of an NOL had eliminated federal tax liability for 2012. There was no federal tax liability to reduce depreciation expense generated by the shorter retirement schedule. Therefore, the Company made a decision to extend the retirement schedule for certain asset categories, which effectively decreased deductions for 2012, and increased depreciation expense for future years. Furthermore, CL&P stated that under IRS tax law, businesses may automatically change from one permissible method of computing depreciation expense for tax purposes to another permissible method upon

the filing of a Form 3115. Therefore, the Company submitted a Form 3115 to the IRS, and adjusted the amounts in Account 28200 to match the filed tax return. If the Company had not taken this action, the NOL would have increased and customers would not have realized any tax benefit of the depreciation expense deduction. Also, the change in retirement schedule was made only for tax purposes, which does not require approval by the Authority. Response to Interrogatory AC-97-SP02, pp. 1 and 2; CL&P Brief, pp. 52-54.

The Authority finds that CL&P's August 2013 adjustment to reduce non-FAS 109 ADITs balance in Account 28200 by $124,742,248 is unsupported. The Authority reviewed distribution plant additions and retirements exhibits and determined that actual distribution plant-in-service as of the end of 2008 was approximately $3,757.116 million. Response to Interrogatory OCC-46 Attachment 1, p. 1. The additions and retirements since 2008 are summarized below:

Table 6

Year	Plant Additions (Million)	Retirements (Million)
2009	$256.891	$ 74.479
2010	$287.992	$ 66.550
2011	$287.791	$ 50.040
2012	$324.484	$ 52.149
2013	$289.038	$ 54.455

Response to Interrogatory OCC-46, Attachment 1, p. 1.

Beginning in 2001, several tax law changes allowed corporations special tax deductions, "bonus depreciation" allowances, above the normal Modified Accelerated Cost Recovery System (MACRS) amounts. The levels of recently allowed bonus tax depreciation deductions are summarized below:

Table 7

Periods Covered	Amount (%)
January 1, 2008 through September 8, 2010[4]	50%
September 9, 2010 through December 31, 2011[5]	100%
January 1, 2012 through December 31, 2013[6]	50%

Since 2008, the deferred tax liability amounts resulting from normalization of tax/book differences have grown exponentially for regulated public utilities. Pursuant to the Uniform System of Accounts as codified in Conn. Gen. Stat. §16-2, Account 282 is credited and Account 410 is debited with an amount by which income tax is lower. This is because liberalized depreciations, such as ACRS, MACRS and/or Bonus deductions,

[4] The Economic Stimulus Act of 2008; the Small Business Jobs Act of 2010; and the American Recovery and Reinvestment Act of 2009.

[5] The Tax Relief, Unemployment Compensation Reauthorization, and Job Creation Act of 2010.

[6] Id.; and the American Tax Relief Act of 2012.

are used for income tax purposes, as compared to straight line depreciations for book purposes. Likewise, Account 282 is debited and Account 411 is credited with an amount by which income tax is greater because liberalized depreciations, such as ACRS, MACRS and/or Bonus deductions, are used for income tax purposes in prior years, as compared to straight line depreciations for book purposes. The amount debited to Account 282 and credited to Account 411 represents current income taxes payable due to smaller amounts of tax depreciation currently permitted for property which liberalized tax depreciation was applied in prior years, as compared to regulatory straight-line book depreciation. There is no evidence provided in this proceeding that would suggest that the deferred taxes accrued and recorded in Account 28200 were overstated and above that permissible by current tax laws. The non-FAS 109 ADIT balances in Account 28200 and annual accretion since 2009 are summarized in the table below:

Table 8

Year	Account 28200 Balance (Million)	Net Change (Million)
2009	$422.736	N/A
2010	$510.410	$ 87.674
2011	$606.298	$ 95.888
2012	$706.560	$ 100.262
2013	$664.267	($ 42.293)

Response to Interrogatory AC-128, Attachment 1 Revision 1, pp. 8, 24 and 33.

Also, annual accretions to the ADITs balances in Account 28200, exclusive of true-up adjustments, are summarized below:

Table 9

Year	Annual ADITs Accretions (Million)
2010	$ 81.039
2011	$ 95.888
2012	$101.330
2013	$ 82.449

Id.

The Company's testimony that the $124,742,248 reduction to the deferred taxes recorded in Account 28200 was a subsequent true-up for an adjustment made in the 2012 income tax return is not supported by the information provided in this proceeding. CL&P's assertion that prior years' tax estimates used to calculate the deferred tax balance are being trued-up by the August 2013 $124,742,248 reduction to the balance in Account 28200 belies tax information provided in this proceeding and is improper. The Authority's review of the Company's distribution unit annual balance sheets for the period 2010-2013, showing that the Company made adjustments to the balance in Account 28200 in August of each year as detailed below:

Table 10

Year	Annual August Adjustment to Account 28200
2010	$6.635 million Increase
2011	Zero Adjustment
2012	$1.1 million Decrease
2013	$124.742 million Decrease

Response to Interrogatory AC-128, Attachment 1 Revision 1, pp. 8; 24, 33; and Revision 2 Attachment, p. 33.

As the tables above indicate, the increase to the ADITs balance in 2012 of $101.33 million does not support the recording of over-estimated amounts requiring a subsequent true-up adjustment of approximately $124.742 million in August 2013. Using the Company's current tax composite rate of 40.85%, the total combined federal and state tax depreciation erroneously estimated for 2012 requiring subsequent revision would be approximately $305.4 million ($124,742,248 / 40.85%). This estimate is very conservative because the federal bonus depreciation allowances cannot be claimed for the calculation of Connecticut corporate taxable income. In its federal tax returns, the Company reported tax depreciation deductions of $541,275,640 in 2011 and $586,677,407 in 2012. The distribution portions of the 2011 and 2012 tax depreciation amounts are $359,956,682 and $384,142,472, respectively. Late Filed Exhibit No. 1-PURA AR-13 Attachment.

The increase in the 2012 tax depreciation amount as compared to 2011 does not support overstatement of estimated tax depreciation amounts based on changes to the retirement schedule for certain asset categories. It is more suggestive of an increase to the regulatory deferred liability associated with book/tax timing differences. Additionally, the retirements recorded in the Company's books in 2012 is $52.149 million. This is based on the Company's testimony that the August 2013 reduction to the ADITs balance in Account 28200 was a true-up adjustment related to its proposed changes to its tax retirement schedule. The estimated increase to the total tax depreciation deductions would be approximately $305.4 million in 2012. This would be in addition to the actual total federal tax depreciation deduction of $384,142,472. The Authority estimated that the additional ADITs that would be recorded in the Company's books in Account 28200 in 2012 would be in excess of $200 million to account for CL&P's proposed changes to its tax depreciation schedule, 100% and 50% bonus depreciation deductions for plant additions in 2011 and 2012, respectively, and MACRS depreciation on pre-2012 vintages. Also, the Authority thoroughly reviewed CL&P's proprietary tax returns filed for 2011 and 2012. Response to Interrogatory AC-10. No information in those returns support any prior period adjustments that would warrant the August 2013 reduction to deferred tax balance in Account 28200.

The Authority is aware of the Company's compliance filing dated August 1, 2013, in which CL&P requested an automatic change to its method for accounting for certain retirement costs by filing Form 3115. This automatic election request was filed on July 10, 2013, with the IRS. CL&P stated that the request for an automatic change in accounting method is to simplify its tax accounting of certain retirement costs through a general asset account election. Response to Interrogatory AC-97 Second

Supplemental, Attachment 2. The Form 3115 referenced was filed protected and not entered into the record in this proceeding. Nevertheless, the Authority evaluates the non-public data and is concerned that the information contained therein actually contradicts the Company's testimony that a change in accounting method did not occur in 2012. According to the Company, the August 2013 true-up adjustment that reduced the ADIT balance in Account 28200 was to reverse estimated deferred taxes recorded in 2012 to reflect a change to a shorter retirement schedule that did not occur.

The Company testified that it recorded larger deferred taxes in Account 28200 in 2012 under the assumption that the tax retirement schedule would be decreased thereby increasing tax depreciation deductions in its 2012 tax returns. In actuality, the Company did the opposite by extending the retirement schedule for certain asset categories and hence, reduced tax depreciation deductions in its 2012 tax returns. The Authority finds it improbable that the Company would forecast and booked additional deferred taxes using a shorter retirement schedule for 2012, which is known to have 50% bonus depreciation and also subsequent to 2011 with 100% bonus tax depreciation deduction. As previously stated, the Authority finds that the additional deferred taxes recorded in Account 28200 in 2012 was in line with expectations, was not overstated and did not warrant the August 2013 reduction adjustment. Also, the Authority determines that the information in the non-public Form 3115 not only contradicts the Company's assertion, but the figures therein are applicable to transmission as well as to distribution operations. Furthermore, the Authority finds that the level of taxable income adjustment made therein did not support the August 2013 true-up adjustment to the distribution ADIT recorded in Account 28200.

A review of an exhibit showing the actual income taxes that the Company paid shows that CL&P's NOL position grew to $118.004 million in 2012 compared to $19.939 million in 2011. Response to Interrogatory OCC-260, Attachment 1. This does not support the position that deferred tax estimates for 2012 were overstated and need to be adjusted in August 2013. Conversely, the exhibit supported the position that a significantly higher tax depreciation was deducted in 2012, which is supported by the 2012 tax return filed under protective order and the PURA AR-13 Attachment. The Authority opines that the higher tax depreciation deductions in 2012 support the booked ADITs increase in 2012. The Authority therefore considers the August 2013 true-up adjustment reducing the deferred tax amount in Account 28200 to be improper and should be reversed.

Based on its review of information provided in Response to Interrogatory OCC-46 Attachment 1, the Authority performed its own analysis of ADIT related to distribution plant for 2012 and 2013 as depicted in the table below:

Table 11

Analysis of Distribution Plant ADIT for 2012 and 2013
($000)

Descriptions	CYE 2012	CYE 2013
Gross Distribution Plant	4,670,378	4,915,903
New Plant Additions	324,484	289,038
Existing Gross Plant	4,345,894	4,616,865
Federal Tax Depreciation – New Additions*	124,115	110,557
Federal Tax Depreciation – Existing Plant**	202,805	210,775
Total Federal Tax Depreciation	327,020	321,332
Less Book Depreciation***	(76,568)	(85,972)
Federal Timing Differences	250,452	235,360
Federal Deferred Taxes (35%)	87,658	82,376
State Total Tax Depreciation (5% of Gross Plant)	233,519	245,295
Less Book Depreciation***	(76,568)	(85,972)
State Timing Differences	156,951	159,323
State Deferred Taxes (9%)	14,126	14,339
Total Deferred Taxes - Federal Plus State	101,784	96,715
Reported ADIT Activities Per AC-9 Attachment 1	103,246	(46,113)
Variances	(1,462)	142,828

*Assumes 70% of new plant additions qualify for 50% bonus depreciation allowances in 2012 and 2013.
**Assumes 5% tax depreciation rate for existing plant not subject to bonus depreciation deductions in 2012 and 2013.
***Cost of Removal was removed from the total book depreciation activity amounts.

Based on the conservative assumptions that only 70% of the new plant additions qualified for bonus tax depreciation deductions and a normal tax depreciation rate of 5%, the Authority calculated a federal tax depreciation deduction of approximately $327.020 million for 2012. This amount is significantly less than the $384,142,472, which the Company reported as the actual distribution plant-related tax depreciation deduction for 2012. Using these cautious assumptions, the Authority also determined total deferred tax accretion of approximately $101.784 million for 2012. The amount aligns with the $103.246 million of additional ADIT that CL&P reported for 2012 and does not support the assertion that excess deferred taxes were recorded in Account 28200 in 2012. For the existing distribution plant and the total new plant additions of approximately $613.522 million in 2012 and 2013, the Authority establishes total additional deferred taxes of approximately $198.499 million. For these two years, with 50% bonus tax depreciation allowances, CL&P reported a total deferred tax increase of approximately $57.133 ($103.246 - $46.113) million. Based on its analysis and discussions above, the Authority concluded that the August 2013 entry that reduced the ADIT balance in Account 28200 by $124,742,248 is incorrect and unsubstantiated.

In its Written Exceptions, CL&P stated the PURA's adjustment to reverse the Company's August 2013 plant-related ADIT adjustment of $124,742,248 in Account 28200 is a mistake because the Authority made incorrect assumptions or followed incorrect accounting practice in assessing the purpose and effect of the adjustment.

According to the Company, the Authority misunderstood the election made by CL&P under IRS regulations in 2013 that actually resulted in a longer tax depreciation period and the accounting treatment of the change. The Company indicated that it did not change to a shorter retirement schedule in 2012. CL&P Written Exceptions, p. 30.

The Company claimed that the balance in Account 28200 as of December 31, 2012, estimated based on transactions occurring in plant assets (retirements, additions and basis adjustments), and the expected deductions under the tax law related to those plant assets. The Company also stated that its computation of tax depreciation expense assumed the traditional retirement schedule, not a shortened retirement schedule, for all asset categories. According to CL&P, the Authority incorrectly assumed the Company used a shortened retirement schedule instead of its traditional retirement schedule in 2012. CL&P Written Exceptions, pp. 31-33.

Contrary to its testimony in this proceeding that the August 2013's true-up adjustment of $124,742,248 in Account 28200 was made so that the deferred taxes on the books agree with the final amounts in its 2012 tax returns, the Company stated that the adjustment amount is made up of the following items:

1. A $74 million reclassification from Account 28200 (deferred tax liability) to Account 28399 (deferred tax liability) to properly distinguish plant-related timing differences from other non-plant related timing differences. The amount transfer Account 28399 has no impact to customers as both accounts work as an offset to rate base. Regardless of the reclassification, this amount was included in rate base as of December 31, 2012.

2. A $47 million decrease to deferred tax liability in Account 28200, which is the result of the Form 3115 Method Change. This change extended the retirement period of certain asset categories for tax purposes creating a smaller depreciation deduction for tax purposes than was expensed for book purposes. The reduction in the liability amount in Account 28200 effectively reduced the timing differences between book depreciation and tax depreciation, but did not represent a negative impact to customers. If the Company had not taken this step, the deferred tax asset recorded in Account 190 related to the NOL would simply have increased by $47 million, resulting in the same rate-base impact as the Company's adjustment.

3. A total of $4 million in minor, routine adjustments that reflect other changes to the estimated liability to what was actually filed on the 2012 tax return.

CL&P Written Exceptions, p. 36.

Finally, the Company stated that the IRS accepted its Form 3115 accounting change. However, CL&P indicated that the Authority's determination to reverse the August 2013 true-up adjustment of $124,742,248 in Account 28200 contradicts the IRS acceptance of the method change and effectively provided deferred tax benefit liability to customers where no such liability exists on the Company's books. According to the Company, the Authority's determination would create a violation of the normalization rules under the Internal Revenue Code. The consequences include an IRS

determination that the Company cannot any longer claim accelerated tax depreciation or similar advantageous deductions permitted under the IRC. Therefore, CL&P requested that the determination in the Proposed Final Decision that reversed its August 2013 true-up adjustment of $124,742,248 in Account 28200 be reversed in the final Decision. CL&P Written Exceptions, pp. 37 and 38.

The Authority's determination is based on testimony provided in this proceeding. The Authority specifically asked the Company to provide the items that caused the August 2013 true-up adjustment of $124,742,248 in Account 28200. The Authority did not indicate that the Company changed to a shorter retirement schedule but that the deferred taxes recorded in Account 28200 was based on CL&P's reconciliation of projected or budgeted deferred taxes recorded in this account in 2012 to reflect the actual tax depreciation deducted in its 2012 tax returns. Tr. 09/25/14, pp. 2730-2734.

The information that the Company furnished in its Written Exceptions regarding the components of the August 2013 true-up adjustment of $124,742,248 in Account 28200 was never entered into record in this proceeding. Therefore, as part of the reopened proceeding discussed above, the Authority will afford the Company and other participants the opportunity to provide exhibits and testimony regarding each component of the $124,742,248 reduction to the ADIT in Account 28200. Similarly, the Authority will allow the Company to record as a regulatory asset the revenue impact of the $124,742,248 to be reconciled when it is finally determined if this amount will be allowed in rate base.

c. System Resiliency

The Authority finds that the revenue requirement proposed for the system resiliency plant additions was overstated. CL&P reported total system resiliency plant addition of $25.554 million in 2013. Schedule B-2.0 (A). The book depreciation related to this plant addition is $198,000. Schedule B-3.0 (A). For 2013, the Company reported ADIT associated with the system resiliency plant addition of only $252,000. Schedule B-7.0 (A). The Authority finds the 2013 ADIT amount related to system resiliency plant addition to be significantly low given that 50% bonus tax depreciation is applicable to 2013 plant additions. Thus, using the 15-year life tax schedule under the half-year convention, the Authority calculates the appropriate ADIT for the 2013 system resiliency plant addition as depicted in the table below.

Table 12

Calculations of ADIT for the 2013 System Resiliency Plant Additions ($000)

Gross Plant Additions*	$25,554,000
Federal Tax Depreciation, Including 50% Bonus Allowance	13,416,000
Book Depreciation**	198,000
Difference	13,218,000
Federal Deferred Tax Benefit at 35%	4,626,000
State Tax Depreciation	1,278,000
Book Depreciation**	198,000
Difference	1,080,000
Connecticut Deferred Tax Benefit at 9%	97,000
Total Deferred Tax Benefit	$ 4,723,000

* Schedule B-2.0 (A)
** Schedule B-3.0 (A)

The federal tax depreciation amount calculated above is 52.5% of the 2013 system resiliency plant addition of $25.554 million. It represents 50% of the 2013 system resiliency plant additions plus 5% of the remaining 50% plant additions not subject to the bonus depreciation allowance. The state tax depreciation amount calculated above is 5% of the 2013 system resiliency plant addition of $25.554 million. Based on the above calculation, the Authority determines that the average ADIT that the Company used to calculate average rate base was underreported by $4.471 ($4.723 - $0.252) million. Consequently, the Authority will similarly reduce the proposed rate base by $4.471 million for the underestimated ADIT connected with the 2013 system resiliency plant addition of $25.554 million.

In summary, the Authority will increase the Company's proposed average ADITs by $170.063 ($124.742 + $40.85 + $4.471) million. Thus, the Authority simultaneously reduces the proposed average rate base by the same amount. This adjustment will restore the normal unwinding of the plant-related deferred tax balance in Account 28200. This will occur as book depreciation deductions catch up and ultimately surpass tax depreciation deductions and fully restore the rate benefits of the increased ADITs derived from allowed significantly larger tax depreciation deductions.

3. Working Capital Allowance

a. Introduction

It is a customary regulatory practice to allow an adjustment to rate base in recognition of the timing difference between when revenues are received and when expenses are paid out. For larger utilities, the Authority typically prefers that a lead/lag study be conducted to determine the appropriate cash working capital allowance rather than using some rule of thumb approach or the utility's balance sheet result. In this proceeding, CL&P conducted such a lead/lag study and requests that the results of that study be used for determining its Rate Year rate base.

Schedule H-1.6 and its supporting Work Papers contained the results of and supporting calculations for the Company's lead/lag study. In conducting its study, CL&P used a stratified random sample of its retail accounts and calculated that it took an average of 40.95 days for CL&P to receive its revenues once service has been rendered based on data through December 31, 2013. WP H – 1.6a, p. 1. Included in this average revenue lag of 40.95 days is a service lag (time between service being provided and the reading of the meter) of roughly 15 to 16 days, a billing lag (time between the reading of the meter and sending out the bill) of two to three days and a payment lag (time between the bill being sent out and the payment being received by the Company) of approximately 23 days (41 days minus 15 days minus 3 days). Tr. 9/24/14, pp. 2444 and 2445. The Company also specifically studied and calculated the expense lead for payroll, payroll deductions, payroll incentives, CTA IPP's, non-bypassable federally mandated congestion costs (NBFMCC), conservation and renewable costs, uncollectible expense, other O&M, ten different categories of taxes, long-term debt, preferred stock and common equity. Based on these calculations and assumptions made regarding the expense lead for other expense categories such as depreciation and amortization, and pension, the Company calculated a cash working capital requirement of $17,230,000 based on a net lag of approximately 3.20 days for the Rate Year. Late Filed Exhibit No. 3, Schedule H-1.6 – Revised. The Authority reviewed CL&P's allowance for working capital request for the Rate Year and finds it acceptable except as discussed below.

b. Non-Cash Items

In its pre-filed testimony and brief, the OCC argued that non-cash expenses should not be part of the lead/lag study because they do not involve an outlay of cash and are excluded by some regulatory jurisdictions in the determination of a working capital allowance. Schultz PFT, pp. 12-15; Brief, pp. 46-49.[7] The OCC also argued that inclusion of non-cash expenses such as depreciation in the cash working capital allowance over compensates the Company by allowing it a double return on the expenses, even when such expenses reduce rate base. Brief, p. 48. To demonstrate

[7] The OCC also expressed concerns with the Company's calculation of expense leads for certain payroll check items, such as payroll taxes and employee deductions, and for income taxes, but made no adjustments related to these concerns. Schultz PFT, pp. 14 and 15, Exhibit_(L&A-1); Brief, p. 47, Schedule B-3, p. 1.

this, the OCC provided a hypothetical where a $100 asset is depreciated over a year. Id. In the hypothetical, the OCC contended that the Company is overcompensated if it gets a return on the average asset in rate base, recovery of the depreciation expense and a working capital allowance on the expense. In reviewing these assertions and contentions by the OCC, the Authority first considered whether ratemaking treatment creates a carrying cost for CL&P relative to the non-cash expenses. When these expenses reduce rate base, the Company is deprived of the return that investment in rate base affords. If there is a lag between the reduction in rate base and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag. As such, it is appropriate for these "non-cash" expenses to be part of a working capital allowance.

The Authority also considered whether inclusion in the lead/lag study as proposed by CL&P over-compensates the Company for the carrying cost of non-cash items. In order for the Company to be overcompensated, the inclusion of non-cash items in the lead/lag study would need to create a situation where a rate base item is still receiving a return after the item has been recovered from ratepayers. In the OCC's hypothetical and as understood by the Authority, the $100 asset is depreciated over the course of a year so that the Company does not fully recover its investment in the asset until the end of the year when it has billed for the last portion of the asset's depreciation expense. As such, it is appropriate for the Company to receive a return on the un-depreciated portion of the asset. In addition, if there is a lag between when the asset in rate base is reduced through depreciation and when the Company receives its cash from ratepayers, an additional return requirement is created. It is this additional return requirement that is provided by inclusion of the depreciation expense (and other non-cash expenses) in the lead/lag study. Finally, as the asset is removed from rate base it is necessary that the depreciation expense itself be recovered from ratepayers. As such, the three piece recovery through the asset in rate base, depreciation expense and as part of a working capital allowance is necessary to keep the Company whole and not overcompensated.[8] The lead/lag study proposed by the Company assumes and/or calculates that depreciation expense (and expense related to amortization and deferred taxes) results in a reduction to rate base after 15 days on average and that funds for this expense are received 25.95 days later. Late Filed Exhibit No. 3, Schedule H-1.6 – Revised. The Authority finds these assumptions and/or calculations appropriate and will allow non-cash items in the lead/lag study as proposed by the Company.

c. Revenue Lag on Costs Recovered through Adjustment Clauses that Use Billed Revenues

In developing the revenue lag for the Company, CL&P included a service lag to account for the time between service being rendered and meters being read. Tr.

[8] In its Written Exceptions, the OCC reasserted that inclusion of depreciation and other "non-cash" expenses in the lead/leg study constitutes a double counting since these costs are already in rate base and earning a return. OCC Written Exceptions, p. 39. In making this argument however, the OCC fails to realize that the lead/lag study only allows a working capital allowance for "non-cash" expense for the period of time when the expense is out of rate base and prior to recovery from ratepayers. As such, there is never a time when the "non-cash" expense is both in rate base and part of the working capital allowance.

9/24/14, pp. 2444 and 2445. While the Company did not specifically break out the service lag from its revenue lag of 40.95 days, based on billing cycles of 27 to 33 days and 12 months in a year, a reasonable estimate of the service lag would be 15.21 days [(365 ÷ 12) ÷ 2]. Tr. 9/24/14, p. 2445. While a service lag is appropriate for revenues associated with most expense categories, it is not appropriate for revenues associated with costs recovered through adjustment clauses that use billed revenues. These types of clauses recover costs based on sales billed during the month, not on sales accrued or delivered during the month. As such, meters are read during the month and trued up through the adjustment clause for service provided during the month. This action by these clauses effectively aligns meter reads with service rendered and eliminates the service lag. Tr. 9/24/14, pp. 2445-2451. The Company identified three of its adjustment clauses as using billed revenues to recover costs. They are: the Competitive Transition Assessment (CTA), the Systems Benefit Charge (SBC) and the NBFMCC. Late Filed Exhibit No. 67. These clauses recover $30,860,000, $41,418,000 and $189,702,000 in Rate Year costs, respectively. Late Filed Exhibit No. 3, Schedule H-1.6 Revised; Tr. 9/24/14, pp. 2441-2443, 2503 and 2504; November 5, 2014 Decision in Docket No. 99-03-36RE22, PURA Determination of The Connecticut Light and Power Company's Standard Offer – 2013 Reconciliation of CTA and SBC, p. 7. For cost recovered through these clauses, meter reads are centered on the midpoint of the month or billing cycle for service centered on the midpoint of the month or billing cycle. Tr. 9/24/14, p. 2446. Therefore, the Authority reduces the revenue lag associated with these costs by 15.21 days. This adjustment and the reasons for it are similar to an adjustment the Authority made in its Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules (June 29, 2011 Decision), for costs recovered through the purchased gas adjustment clause (PGA). June 29, 2011 Decision, pp. 36 and 37.

In its Brief, the Company attempted to distinguish the PGA from the CTA, SBC and NBFMCC by asserting that the latter clauses have a lack of consistency in the sales growth, a lack of monthly reconciliation, that the change from using accrued revenues to using billed revenues is onetime in nature, that they will operate with a decoupling mechanism and that there is a greater lag between when payment is received and when payment clears for CL&P. CL&P Brief, pp. 91 and 92. Based on these alleged differences, the Company concludes that there is no on-going beneficial timing difference to CL&P from using billed revenues to collect costs in three of its adjustment clauses. While the alleged differences may or may not apply, they do not impact the revenue lag difference between using billed revenues to recover costs vs. using accrued revenues to recover costs. This is because for any given period and on average, billed revenues are billed at midpoint of the period and accrued revenues are only accrued at the midpoint of the period to be billed at the end of the period. Relative to accrued costs, this means that billed revenues are 15 or so days closer to being received by the Company [30 (end of period) minus 15 (midpoint of period) equals 15 days (timing benefit from using billed revenues)]. This timing benefit is not impacted by the consistency of sales growth, the timing of reconciliations (provided carrying costs are included), the onetime nature of the change from accrued revenues to billed revenues (the benefits continue as long as billed revenues are used), the presence of a decoupling mechanism or the length of other lag components in the revenue lag. As such, despite the Company's objections, a 15.21 day reduction to the revenue lag associated with costs recovered by the CTA, SBC and NBFMCC is appropriate.

d. Adjustments to Expense Amounts

In addition to adjustments to the lag days for some expense categories, the Authority also made adjustments to the amount of expenses or income allowed for ratemaking purposes. These adjustments are detailed throughout this Decision and impact the working capital allowance the Company needs. The Authority adjusted the expense and income levels used to calculate the working capital needs of the Company to mirror the expense and income adjustments made by this Decision.

e. Conclusion

Based on the adjustments detailed above related to working capital, the Authority calculates a working capital allowance for the Company of $15,361,000 for the Rate Year, including the 15 basis point ROE penalty. This amount is based on a Rate Year net lag of 3.01 days and is $1,869,000 less than the $17,230,000 proposed by the Company. As such, the Authority reduces the working capital allowance $1,869,000 for the Rate Year. If and when the ROE penalty goes away as allowed by this Decision, the working capital allowance becomes $14,779,000, based on a net lag of 2.89 days, and is $2,451,000 less than the $17,230,000 proposed by the Company.

4. Reserves – Net of Deferred Income Taxes

In its Applications, CL&P reported total net regulatory liabilities or reserves of $37.148 million for the test year ending December 31, 2013, $36.915 million for the proforma period ending December 31, 2014, and $42.569 million for the proposed Rate Year ending December 31, 2015. Schedule B-8.0. Hence, the Company originally reported as an offset to rate base average total net reserves of $39.86 million for the Rate Year. Schedule B-8.0. In its updated filing, CL&P reported total net reserves of $37.728 million for the proforma period ending December 31, 2014, and $43.3829 million for the proposed Rate Year ending December 31, 2015. Late Filed Exhibit No. 3, Schedule B-8.0 Revised. The updated total average net reserves for the Rate Year is $40.555 million. Id., Schedule B-1.0 Revised.

The total average net reserves for the Rate Year included average net storm reserves of $7.689 million. Late Filed Exhibit No. 3, Schedule B-8.0 Revised. Based on the discussions in Section II.C.13, Storm Reserve, the Authority disallowed the recovery of $6 million of storm reserves in O&M expenses. Thus, the Authority will reduce the average net reserves by $1.775 ($6 / 2) X (1 - 0.4085)) million. Conversely, the rate base for the Rate Year is increased by $1.775 million.

5. Conclusion on Rate Base

The rate base approved in this Decision is $3.233 billion as identified in Section III.V.B.

C. EXPENSES

1. Depreciation

A depreciation rate study calculates the annual depreciation rate. The depreciation rate is then applied to the gross plant-in-service balance. The product of this calculation is the depreciation expense, which is a charge to a company's operating expense to reflect the annual recovery or amortization of previously expended capital investment. The Company stated that the Test Year depreciation expense was $107 million and the projected Rate Year 2015 plant depreciation and amortization expense is $140 million. Application, Schedule C-3.32. CL&P filed a depreciation rate study, conducted by Mr. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming), for utility plant owned and operated by CL&P as of December 31, 2013 (2013 Study).

a. General Concepts of Depreciation

Since the depreciation expense represents the annual recovery of the capital investment, the asset base of the utility is diminished with each year. The amount of depreciation that has been taken is booked in an account called the accumulated provision for depreciation, also known as the booked reserve.[9] All depreciation expense, retirements, cost of removal and gross salvage are booked in the booked reserve. The accumulated provision for depreciation, or booked reserve, serves as a "running total" of the extent to which individual assets or groups of assets have been depreciated. The theoretical reserve[10] is a calculation of what the depreciation reserve should be based on the current estimates of average service life (ASL), survivor curve and net salvage estimate. The comparison between the booked reserve and the theoretical reserve provides a metric of the accuracy of past depreciation rates.

In the case of a regulated utility, recovery of investor–supplied capital is dependent upon allowed revenues, which are dependent upon approved levels of the depreciation expense. Periodic reviews of depreciation rates are essential to the achievement of timely capital recovery for a regulated utility. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The ASL of a vintage is a statistic that will not be known with certainty until all units from the original placement have been retired from service. Therefore, a vintage ASL must be estimated initially and periodically revised as indications of the eventual ASL becomes more certain. A mathematical description of survival functions or survivor curves of retirement acting upon a plant category is determined from an estimation of service life statistics and an analysis of past retirement experience. The life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve to predict the expected remaining life of property units still exposed to the forces of retirement. The amount of

[9] Booked reserve is also known as recorded reserve or actual reserve.
[10] Theoretical reserve is also known as required reserve.

weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category.

The level of asset grouping identified in the broad group procedure is the total plant-in-service from all vintages in an account. Each vintage is estimated to have the same ASL. The remaining life of each vintage is estimated from a projection life curve and the attained age of the vintage. The average remaining life for a broad–group plant account or rate category is a direct, dollar–weighted average of the remaining life of each vintage. The weights used in this calculation are the vintage survivors at the beginning of the study year.

Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are estimated parameters of a depreciation system that are subject to future revisions. Plant accounting data is utilized to conduct a statistical analysis of past retirement experience and analyzed to determine the relationship between retirements and realized gross salvage and cost of removal. An estimate of the net salvage rate applicable to future retirements is obtained from an analysis of the gross salvage and cost of removal realized in the past.

An analysis of past experience and trends over time provide a baseline for estimating future salvage and cost of removal. Consideration should be given to events that may cause deviations from net salvage realized in the past such as the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past. Judgment of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials were used in developing estimates of the future. 2013 Study, Exhibit JJS-2, p. IV-2. Average net salvage rates are estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements of the surviving plant with the estimated future net salvage rate.

Included in the depreciation study is an analysis of the adequacy of the booked depreciation reserve. The purpose of such an analysis is to compare the current balance in the booked reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the theoretical or required reserve and the booked reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are commonly maintained by various account classifications, the total booked reserve in relation to the sum of account computed reserves is a good indicator of the adequacy, or inadequacy, of booked reserves. Differences between theoretical and booked reserves will arise as a normal occurrence

when service lives, dispersion patterns and net salvage estimates are adjusted in depreciation reviews. Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system.

b. CL&P 2013 Study

CL&P filed the 2013 Study to estimate the appropriate annual depreciation accruals for CL&P's plant-in-service as of December 31, 2013. Three elements – method, procedure and technique – are needed to describe a depreciation system. Since 2009, CL&P has been using a depreciation system composed of the straight line method, ASL procedure, and remaining life technique. This is a system widely used by regulated utilities. Depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The remainder of this section describes the 2013 Study performed by Gannett Fleming.

A depreciation study was completed in 2009 for the 2009 CL&P Rate Case (2009 Study) for properties in service as of December 31, 2008. The Company's accounting policy has not changed since that study. The 2013 Study requests an annual depreciation expense of $138.8 million when applied to plant as of December 31, 2013. 2013 Study, pp. 6 and 7. Table 13 shows the results from the 2013 Study that includes the amortization approved to correct for the $380.5 million reserve imbalance seen in the 2009 Rate Case.

Table 13

Summary of 2013 Depreciation Expense ($000)

		ANNUAL ACCRUAL					
Function	Original Cost	Rate (%)	Amount	7 Year Amortization	Remaining Life Amortization	Total Adjusted	Adjusted Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)+(5)+(6)	(8)
Distribution	4,455,939	2.93	130,402	(10,305)	(8,491)	111,605	2.50
General Plant	231,658	3.34	7,733	(264)	(218)	7,250	3.13
Unrecovered Reserve Amortization			674			674	
Transportation Equipment	61,450						
Nondepreciable Plant	161,450						
Total Plant-in-service	4,910,498		138,810	(10,570)	(8,710)	119,530	

2013 Study, Exhibit JJS-2.

Table 14 provides a summary of the changes in annual rates resulting for total depreciable plant from adoption of the parameters and depreciation system recommended in the 2013 Study based on total plant investments of $4.7 billion.

Table 14

Current and Proposed Depreciation Annual Accruals

Account	Original Cost	Proposed Annual Accrual	Current Annual Accrual	Increase/(Decrease)
(1)	(2)	(3)	(4)	(5)=(3)-(4)
Distribution	$4,455,939,516	$111,605,156	$80,454,721	$31,150,435
General Plant	$231,658,093	$7,250,386	$7,674,419	($424,033)
Unrecovered Reserve Amortization		$674,989	0	$674,989
Total Depreciable Electric Plant	$4,687,597,608	$119,530,531	$88,129,140	$31,401,391

2013 Study, Exhibit JJS-3

As of December 31, 2013, the total booked reserve for the Company was $1.103 billion and the theoretical reserve is $1.17 billion, for a difference of $67 million. When the book reserve is less than the theoretical reserve as in the current case for CL&P, it means that the depreciation rates used in the past were too low. Plant was being depreciated at a slower rate than it should have been. Mr. Spanos stated that this level of reserve imbalance is insignificant relative to the level of reserve. Tr. 9/2/14, p. 715.

CL&P requested an increase of $30 million (Schedule C-3.32; LFE-3, Sch. 3.0 (revised) line 59). This increase was due to changes in life parameters, net salvage accruals, and resulting changes in reserve amortizations. CL&P Brief, p. 43. An increase in the depreciation expense in the amount of $18.5 million was caused by changes in net salvage. Further, the changes in life and net salvage parameters in the 2013 Study resulted in a $66 million deficiency in the reserve balance. For total depreciable plant, the actual book reserve is $1.103 billion and the theoretical reserve is $1.169 billion. 2013 Study, Exhibit JJS-4a. Therefore, a $16.2 million increase in expense was included to correct for the deficiency in the theoretical reserve. Spanos PFT, p. 15. CL&P testified that the $66 million reserve imbalance would be distributed to the individual vintages and recovered over the remaining life. Tr. 9/2/14, pp. 689 and 690.

c. Positions of the OCC and the AG

The OCC and AG recommended a reduction of $19.5 million in depreciation expense due to adjustments to ASL parameters, net salvage parameters and adjusting the amortization periods for six software accounts. OCC Brief, p. 81; AG Brief, p. 12. The OCC contended that multiple adjustments need to be made to CL&P's proposed depreciation expense. First, the OCC proposed adjustments to CL&P's analyses of mass property life parameters for two accounts: Account 362 – Distribution Station Equipment and Account 365 – Overhead Conductor and Devices. OCC Brief, pp. 91 and 95. Second, the OCC proposed adjustments to mass property net salvage values for four accounts: Account – 362 Distribution Station Equipment; Account 364 – Poles, Towers and Fixtures; Account 367 – Underground Conductors and Devices; and

Account 367 – Services. Pous Revised PFT, p. 31. Third, the OCC recommended extending the amortization period for 6 software systems from a 10-year amortization period to a 15-year amortization period and that any new software plant additions be amortized over a 15-year period. OCC Brief, p. 108. Based on these adjustments, the OCC recommended a total reduction of $19.5 million in depreciation and amortization expense. Pous Revised PFT, p. 6. In addition to these adjustments, the OCC argued that CL&P has not met the burden of proof required to support its depreciation expense request. OCC Brief, p. 82.

The AG claimed that the 2013 Study understates the ASL of its physical plant and overestimates its future negative net salvage costs. AG Brief, p. 12. The AG also supported the OCC's recommendation for extending the amortization period of specific software systems to 15 years. Id., p. 15.

d. Analysis

The accounts under dispute for mass property life parameters are Account 362 - Station Equipment and Account 365 – Overhead Conductors and Devices. The accounts under dispute for net salvage parameters are Account 362 – Distribution Station Equipment; Account 364 – Poles, Towers and Fixtures; Account 367 – Underground Conductors and Devices; and Account 369 – Services. These disputed accounts are addressed below.

i. Mass Property Life Parameters

There is no dispute that the calculation of annual depreciation expense based on the straight line method used in the 2013 Study requires the estimation of survivor curves. Both the OCC and the Company proposed to update survivor curves for Account 362 and Account 365 from the existing ones used to determine depreciation expense in the 2009 Study.

The OCC proposed adjustments to two mass property accounts, Account 362 - Distribution Station Equipment and Account 365 – Overhead Conductor and Devices. Table 15 shows a summary of the OCC and CL&P proposed survivor curves. The current survivor curves used for determining depreciation expense are 50-R2 for Account 362 and 50-SC for Account 365.

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Table 15

OCC's Recommended Mass Property Life Adjustments

Account	CL&P Proposed	OCC Proposed	OCC Adjustment	Dec. 31, 2013 Impact
362	51S0	54S0	3	$1,084,726
365	44O1	48L0	4	$3,671,710
Total				$4,756,436

Pous Revised PFT, p. 10.

The OCC's witness indicated that these adjustments were based on: 1) an independent review of the actuarially derived life indications; 2) information provided by the Company's personnel; 3) information obtained during discovery; and 4) from previous experience in "performing hundreds of depreciation analyses." Pous Revised PFT, pp. 10 and 11.

(a) Account 362 – Station Equipment

Account 362 – Station Equipment includes the following facilities: control equipment such as transformers, batteries, remote relay boards and connections; primary and secondary voltage connections and associated equipment; switching equipment; switchboards; fixed and synchronous condensers; bus compartments; conduit; conversion equipment; fences; foundations and settings; and general station equipment.

The existing survivor curve used to determine the depreciation expense for this account is 50R2. The Company proposed a 51S0 survivor curve and the OCC proposed a 54S0 survivor curve. 2013 Study, Exhibit JJS-2, p. VII-13; Pous Revised PFT, p. 19.

The OCC argued that CL&P's proposed survivor curve of 51S0, understates the realistic ASL. Pous Revised PFT, p. 19. The OCC further contended that from an actuarial standpoint, historical data for experience bands of 1916-2013, 1964-2013 and 1998-2013 indicate a significant trend towards a longer ASL that is not accounted for by the Company's analysis. Pous Revised PFT, pp. 20-23.

The Company justified use of its survivor curve by saying that "there is a plan to upgrade substation equipment more aggressively in the next few years to handle load requirements and technology advancements" which supports an ASL of 50 years. Response to Interrogatory OCC-001. Further, while station equipment in general is experiencing slightly longer ASL, relay equipment will see a higher level of early retirements. Response to Interrogatory OCC-003. The OCC argued that relay equipment is only a 7% investment in this account and should not restrict "a realistic increase in ASL for this account." Response to Interrogatory OCC-022; Pous Revised PFT, p. 23. The OCC further argued that the early retirement of relay equipment is already reflected in the historical data. Pous Revised PFT, p. 23.

The Company contended that the overall experience band of 1916-2013 should be used in this case for determining the most appropriate survivor curve. Spanos Rebuttal, p. 20. The Company argued that the 1998-2013 experience band is not indicative of future trends for this account because from 1999-2003, there was a focus on retiring older assets which would cause the retirements as a relationship to exposure to be lower. The Company claimed that this trend will not continue since there will be a focus on substation reliability work in the next 5 years that will result in retirements of not only old assets, but also of assets in the 30- to 40-year range. Tr. 9/2/13, pp. 698 and 699. The Company also claimed that, in addition to the primary reasons for past retirements – such as failure, wear and tear, load and demand – reliability and system integrity have become the dominant causes of retirement and the more technology-based assets can cause a higher percentage of retirements. Response to Interrogatory

OCC-007. The Company also showed that retirements have increased annually in the 2009-2013 time period to an average amount of $3.8 million, as compared to an average amount in the prior five years of $1.3 million. Response to Interrogatory OCC-023; CL&P Reply Brief, p. 34.

The Authority concurs that the recent trends in the historical data for the 1998-2013 experience band data are not necessarily indicative of future retirements for this account. The Authority accepts the OCC's argument that there is an obvious trend in the data when all three experience bands are analyzed. In fact, the Company acknowledged that the 1964-2013 experience band is "representative of the database." Tr. 9/2/14, p. 695. Accordingly, the Authority determines that the historical data in the 1964-2013 experience band should be heavily weighted for this account. Therefore, the Authority finds the OCC's proposed 54S0 curve to be a better match to the 1964-2013 experience band as it best reflects the most accurate representation for life parameters for this account. This results in a $1,084,726 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 23.

(b) Account 365 – Overhead Conductors and Services

Account 365 – Overhead Conductors and Devices includes the following facilities: Conductors; circuit breakers; ground wires and clamps; insulators; lightning arresters; railroad and highway crossing guards; splices; switches; and other line devices.

The existing survivor curve for this account is 50SC. The Company proposed a 4401 curve, which is a reduction in ASL of six years. The OCC proposed a curve of 48L0 which is a reduction in ASL of two years.

The OCC argued that its life curve combination is similar to the Company's curve, but that when "neither actuarial analysis nor information external to the historical data provides strong support for a change in ASL" then the existing parameter should be retained. OCC Brief, p. 95. Since the curve fits are similar, the OCC contended its curve is more appropriate since it does not result in a significant decrease in ASL. Pous Revised PFT, p. 25. The OCC further justified the use of its curve by noting that CL&P has not stated any changes in policies or practices that would warrant the six year reduction in ASL. The OCC also argued that the age of overhead conductors, with more than 50% over 40 years of age and at least 33% over the age of 50 years support the use of OCC's recommended curve. Finally, the OCC claimed that the recent storms experienced by CL&P may reduce the perceived ASL in the actuarial analyses. Id., pp. 27 and 28.

The Company argued that the L0 dispersion pattern for the OCC's proposed curve is unrealistic since its views overhead conductors as the longest lived asset for that account and that 90 to 100 years is an appropriate number for longest service life. Tr. 9/2/14, pp. 678 and 680. The OCC countered that insulator pins and posts have a longer service life than conductors and that "only $100 in assets out of a $1.2 billion account would need to live 160 years to validate an L0 dispersion pattern." Tr. 9/2/14,

p. 734. The Company stated that typically insulator pins and posts are replaced when the conductor is replaced. Tr. 9/2/14, p. 680.

The Authority finds that of the historical data for this account support the Company's statement that the longest lived assets range from 90 to 100 years. Spanos Rebuttal Testimony, p. 22. The Authority also finds that although the curves are similar, the Company's curve is a superior fit and the OCC's curve is only a better fit to the historical data for a portion at the tail end of the curve where neither party believes much emphasis should be placed. The Authority accepts the Company's life curve combination for this account.

ii. Net Salvage Parameters

The Company's net salvage estimates were based on "judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials." Spanos PFT, Exhibit JJS-2, p. IV-2. A negative net salvage percent occurs when cost of removal is greater than salvage return. The Company compiled historical data from 1999 through 2013. Id. The OCC agreed with the Company that averages of the historical data are not always representative of future net salvage. Pous Revised PFT, p. 32. These figures are important since these costs were incurred in practice. The Authority will use these figures to ensure that these costs will not be shifted to future customers of the Company. Table 16 below displays the 15-year historical average and the five-year moving average for net salvage costs. Negative net salvage percentages are displayed in parentheses.

Table 16

Average Net Salvage Values

Account	Overall Average	5-Year Average
362	(58)	(61)
364	(138)	(100)
367	(83)	(81)
369	(222)	(450)

Spanos Rebuttal Testimony, p. 24

CL&P argued that from 2009 – 2013, the Company has incurred larger costs of removal than has been accrued. This data presented in Table 17 below is derived from Spanos PFT, p. 14.

Table 17

Incurred vs. Accrued Cost of Removal

Year	Incurred	Accrued
2008	30,761,664	9,795,406
2009	19,744,032	12,239,899
2010	21,368,525	12,944,564
2011	30,401,991	13,585,052
2012	31,826,451	14,603,464
2013	25,699,305	15,520,100

The Company further argued that it should at least accrue for as much as it incurs and since it is a growing company, it should be allowed to accrue more than what it has been incurring. Tr. 9/2/14, pp. 702 and 703. The Company argued that the goal with net salvage recovery in this proceeding is to correct for the under recovery seen in recent years and to gradually move the Company towards full recovery. CL&P Reply Brief, p. 36. The Company expected that the net salvage values will need to be more negative in the future. Tr. 9/2/14, p. 716.

The OCC proposed net salvage adjustments to four Mass Property Accounts: 362 – Distribution Station Equipment; 364 – Poles, Towers and Fixtures; 367 – Underground Conductors and Devices; and 369 – Services. Table 18 summarizes CL&P's proposals and the OCC's recommended adjustments and their impact on the Company's proposed depreciation expense.

Table 18

Proposed Net Salvage Adjustments

Account	CL&P Existing	CL&P Proposed	OCC Recommended	OCC Adjustment	Impact
362 – Distribution Station Equipment	(30%)	(35%)	(25%)	(10)	$1,437,561
364 – Poles, Towers and Fixtures	(50%)	(60)%	(50%)	(10)	$1,143,856
367 – Underground Conductors & Devices	(10%)	(25%)	(15%)	(10)	$1,904,773
369 - Services	(20%)	(100%)	(50%)	(50)	$3,542,746
Total					$8,028,935

Pous Revised PFT, p. 31.

(a) Account 362 – Station Equipment

The existing net salvage approved for this account is -30%. The Company proposed a -35% net salvage and the OCC proposed a -25% net salvage value. Pous Revised PFT, p. 32. The OCC argued that the Company provided no valid basis to

propose a more negative net salvage than the existing value. The OCC claimed that the Company's industry database better supports the OCC's proposed net salvage value of -25%. Id. The OCC further stated that transformers, which comprise 35% of the investment in this account, but only 23% of the dollar-related retirement activity should provide some positive salvage to offset cost of removal. The transformers also contain large quantities of copper, which should result in offsetting salvage. Id., pp. 32 and 33.

The Company argued that the value presented by the OCC would accrue less in depreciation expense for cost of removal than the Company incurred annually. Spanos Rebuttal Testimony, p. 26. The OCC, however, showed that its recommended level of cost of removal, when divided by the remaining life, exceeds the annual average cost of removal for the last three years by 24%. OCC Brief, p. 102. The OCC also contended that the high dollar cost transformers will have a less negative percentage level of net salvage than other types of assets when retired. Id., pp. 102 and 103.

Based on the most recent three year statistics for cost of removal, a -25% net salvage value will allow CL&P to accrue more than it incurs, while still providing room for growth. Therefore, the Authority accepts the OCC's recommendation of a -25% net salvage value for Account 362 – Distribution Station Equipment. This results in a $1,437,561 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 34.

(b) Account 364 – Poles, Towers, and Fixtures

The existing net salvage approved under rates for this account is -50%. The Company proposed a -60% net salvage and the OCC proposed a -50% net salvage value.

The OCC contended that CL&P failed to adequately justify its increase in a negative net salvage for this account. The OCC recommended retaining the existing net salvage value of -50%. Pous Revised PFT, p. 34. It argued that major storms contributed to the higher costs of removal seen in recent years and that the Company's historical database better supports its net salvage value. The OCC maintained that recent major storms resulted in higher net salvage costs for this account, artificially increasing the negative net salvage levels. Id.

CL&P stated that most of the storm costs were removed when calculating net salvage parameters for the study since the Company "didn't want to have our going forward estimates to include that in our total salvage." Tr. 9/2/14, p. 704. The Company also stated that the STORMS software system, in use since 2006, allows for more accurately recording removal costs and factored into this net salvage value. Spanos Rebuttal Testimony, p. 28.

While the Company has shown that in general, it is incurring more salvage costs than it is accruing, there is no specific data on the record for Account 364 that supports an increase in the negative net salvage value for this account. In the Proposed Final Decision, the Authority accepted the Company's proposed -60% net salvage value for this account based on CL&P's claim that storm related costs were isolated from the

historical data. However, in its Written Exceptions, the OCC noted that the Company did not remove the impact of recent storm costs from its proposal. OCC Written Exceptions, p. 21. Specifically, the Company acknowledged in Late File Exhibit No. 14 that the incurred cost of removal amounts set forth in Table JJS-1 on page 4 of Spanos PFT did not distinguish major storm related removal costs. Further, while the Company stated that the STORMS software system more accurately records removal and salvage costs, it admitted uncertainty as to how detailed the system is with isolating specific costs related to storm work. Tr. 9/2/14, pp. 708 and 709. Finally, the Company assigned removal costs in 2006 and 2007 to Account 364 from earlier years' retirements that were delayed in being recorded. Also, the Company undertook large projects that involved retirements from both Accounts 364 and 365 and assigned large amounts to Account 364 and very little to Account 365. Response to Interrogatory OCC-214.

The Authority finds that the Company did not provide adequate justification to increase the net salvage values for Account 364. The historical data does not clearly isolate major storm costs as the Company initially claimed. Further, salvage costs assigned to Account 364 in 2006 and 2007 were not necessarily associated with those years or with that specific account. Therefore, the Authority accepts the OCC's argument to retain the existing -50% net salvage value for Account 364 – Poles, Towers and Fixtures. This results in a $1,143,856 reduction in annual depreciation expense based on plant as of December 31, 2013. Pous Revised PFT, p. 36.

(c) Account 367 – Distribution Underground Conductors and Devices

The existing net salvage approved under rates for this account is -10%. The Company proposed a -25% net salvage value and the OCC proposed a -15% net salvage value. Both net salvage values proposed are well below the negative 83% over the last 15 years and the negative 81% from the most recent 5 years.

The OCC argued that the Company did not provide sufficient evidence supporting the -25% value outlined in the study. Pous Revised, PFT, pp. 38 and 39. The OCC contended that its proposed value is superior since most underground conductors are abandoned in place and that industry trends show more cables are installed in conduit rather than direct-buried. Id., p. 39. According to the OCC, this should result in lower cost of removal since retired cable in conduit can be pulled out when not retired in place. Id.

The Company countered that most conductor in conduit has only been placed in the last 30 to 40 years and that the ASL of this account is 50 years, so the overall impact of removing retired cable from conduit will not be seen for many years. Spanos Rebuttal Testimony, p. 29. The Company further argued that the practice of abandoning direct buried conductor is a practice that has not changed and is already reflected in the cost of removal statistics. Id.

The Authority finds the Company's net salvage value for this account to more accurately reflect the historical data and the outlook for net salvage in the near future. Therefore, the Authority approves the Company's net salvage value of -25%.

(d) Account 369 – Distribution Services

The existing net salvage approved under rates for this account is -20%. The Company proposed a -100% net salvage and the OCC proposed a -50% net salvage value.

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The OCC argued that the Company has not provided adequate justification for a five-fold increase in net salvage. OCC Brief, p. 106. The OCC also argued that the Company's claim that more services will be underground and will increase the negative net salvage is not supported by the industry database. Pous Revised PFT, p. 44. The AG opposed the increase and notes that "a negative net salvage of 100% means that for every dollar of plant invested, the Company expects to incur and additional dollar in the future to remove it." AG Brief, p.14.

The Company acknowledged that the five-fold increase does not necessarily appear gradual, but it is an appropriate change considering the historical indications that show a negative 222% net salvage over the last 15 years and a negative 450% net salvage from the most recent 5 years. Spanos Rebuttal PFT, p. 31; 2013 Study, Exhibit JJS-2, p. VIII-9. The Company also acknowledged that the negative 450% 5-year average for net salvage for this account is not appropriate. Spanos PFT, p. 30. The Company argued that the current negative 20% net salvage selected in the 2009 CL&P Rate Case was artificially low to correct the reserve imbalance. CL&P Response to Interrogatory OCC-218. The Company further argued that, recently, older than usual retirements have occurred for this account and that it therefore expects negative net salvage of 100% to 150%. CL&P Response to Interrogatory OCC-218.

The Authority finds the Company's request for an increase to negative 100% net salvage for this account is unsupported by the record. Specifically, when asked for support and justification for this increase in Interrogatory OCC-218, the Company provided only general expectations. Further, there is nothing in the 2009 CL&P Rate Case that supports the Company's claim that the current net salvage value was artificially low. The Authority therefore rejects the Company's request. The Authority accepts the OCC's recommendation of a negative 50% net salvage, which is more than double the current value. The Authority finds this value to more reasonably represent a gradual approach to full recovery for the Company. This net salvage value results in a $3,542,746 reduction in annual depreciation expense based on plant as of December 31, 2013.

iii. Software Amortization

The OCC argued that for Account 303 – Intangible Plant – Software, intergenerational inequity exists and that $44 million of investment in these systems is already amortized but is still in service. Pous Revised PFT, p. 47. This accounts for nearly 30% of the total investment. Id. The OCC recommended extending the amortization period of 6 accounts currently under a 10-year amortization period that are not fully amortized to have their amortization period extended to 15 years. Id., p. 48. The OCC also recommended the $14 million of additions to Account 303 in 2014 and 2015 be amortized over a 15-year period (Company Schedule B-2.1, line 23). Id., p. 49. The OCC further recommended that "any new plant additions subsequent to December

31, 2013 to which CL&P would assign a 10-year amortization period, also be assigned a 15-year amortization period." OCC Brief, p. 108. The OCC claimed that customers who are receiving the benefit of this software are not paying for it and that 30% of the entire software investment is fully recovered, but still used and useful. Response to Interrogatory OCC-348; Pous Revised PFT, p. 47. The OCC also argued that the base rate revenues recovered for an amortization expense become additional return on investment when the system that provides service is fully amortized. Pous Revised PFT, p. 48. The OCC claimed that CL&P ceases to record an increase to the amortization reserve when the individual system becomes fully accrued, but the Company still collects revenue dollars from customers. Id.

According to CL&P, software amortization was not covered in the 2013 Study as it was supported by the Company's accounting group. CL&P Reply Brief, p. 37. CL&P developed estimates for its software amortizations using its accounting group and Company IT professionals and the timeframes they apply are three, five and ten years. Tr. 9/2/14, pp. 709 and 710. CL&P agreed that some software systems have lasted longer than the original estimated life, but did not believe that the Company historically underestimates the useful life of its systems. Id., p. 711.

The Authority concurs that the amortization period is intended to be the period over which the investment is used and useful so that customers that receive the benefit of the asset pay for the asset. Pous Revised PFT, p. 46. The Company owns 67 software assets as of December 31, 2013. Of these, 45 have been fully amortized but are still in service. As mentioned above, this accounts for nearly 30% of the total software investment. However, all but one of the 45 systems cited above are assigned a 5-year amortization period. CL&P Response to Interrogatory OCC-348, Attachment 1. Those systems contributed the most to $44 million worth of plant still in service yet fully amortized. Therefore, the Authority finds it inappropriate to assign a 15-year amortization period for the Company's software systems that are currently assigned a 10-year amortization period since these systems have not contributed to the 30% of fully recovered investment. Further, even though 30% of the systems used by the Company are fully amortized, the OCC acknowledged that it is "reasonably" possible for some software to be taken out of service prior to the end of its amortization period. Response to Interrogatory CL&P-12. For these reasons, the Authority rejects the OCC's recommendation to impose a 15-year amortization period on the software systems that are currently assigned a 10-year amortization period. However, the Authority will adopt the OCC's recommendation that the Company perform a complete and well documented analysis of expected service periods for its existing and new software systems prior to its next rate proceeding. Pous Revised PFT, p. 49.

2. Payroll

The Company originally requested a Rate Year payroll expense of $135.881 million which includes both base and overtime payroll. Schedule C-3.26. Subsequently, the Company revised the request to $135.198 million, a decrease of $683,000 for reduced overtime due to the troubleshooters program. Late Filed Exhibit No. 3, Revised Schedule C-3.26 and Revised WPC-3.26.

a. Full Time Equivalent Positions (FTEs)

The requested Rate Year payroll expense of $135.198 million is for FTEs as of January 1, 2014. CL&P Brief, p. 27. The 4,435.8 requested Rate Year FTEs are comprised of CL&P employees and 26.2% of the cost of the employees working for the Northeast Utilities Service Company (NUSCO). NUSCO provides centralized accounting, environmental, legal, purchasing, security and other services to CL&P and the other affiliates of NU. Id. The Rate Year FTEs were calculated by beginning with the total FTEs as of January 1, 2014 (4610.8 FTEs) and subtracting the NUSCO 175 FTEs that were leaving due to the NUSCO IT reorganization. Id., p. 28. The Company claimed that between the closing of the merger in April 2012 and the end of the Test Year, the NU organization has already reduced staffing levels in other areas, with the savings reflected in the revenue requirement for this case. Joint Rebuttal Testimony of Bowes and Michelson, p. 15.

The Company further stated the positions that remain are needed to operate the distribution system and provide service to customers. Disallowing funding for 131.2 positions would have a substantial adverse impact on the Company's ability to execute its operational and business plan successfully for the Rate Year. Id. During the hearings, when asked to elaborate and explain this statement, the Company witness stated that as to a specific substantial impact he did not know. Tr. 9/12/2014, pp. 2305-2307. The witness went on to state that if the employee level was cut, the Company would have to find a way to handle that workload, which if not handled by one of its internal FTEs, would have to be handled by outsourcing, either as a temporary situation or by another contractor. Id.

The Company was also asked to provide an update on the total number of FTEs as of August 31, 2014. The total FTEs as of that date was 4,253.8. Late Filed Exhibit No. 55, Attachment 1, p. 1. The Company stated that between August 31, 2013 and August 31, 2014, 201 positions opened-up due to attrition. Id. Of the 201 open positions, CL&P is actively seeking to fill 101. Of the remaining 100 open positions, 68 are allocated to CL&P and 32 to NUSCO. In addition, the Company provided a listing of the 101 CL&P and NUSCO open/approved positions as of August 31, 2014. Id., Attachment 2, p. 1. The Company provided the status update as of September 5, 2014, for those CL&P and NUSCO May 31, 2014 Open Positions. Late Filed Exhibit No. 54, Attachment 1, p.1. The Company claimed that open positions are always filled; it does not have vacancy rate information, nor does it track that information. Tr. 9/12/2014, pp. 2295-2297.

The OCC originally proposed a reduction to the Company's requested payroll expense of $6,255,239. OCC Brief, p. 50. This reduction was based on an adjustment of 102 FTE positions for the remaining IT positions that had yet to be vacated. Id. Subsequently, the OCC revised its adjustment to correct the error associated with the actual number of IT positions remaining as of May 2014. Id. The revision, based on June 1, 2014 FTEs and a reduction of the original adjustment from 102 to 29 FTEs (due to the error in calculating the remaining IT employees), resulted in a recommended reduction to the payroll expense of $4,019,037. Id.

The OCC made a further revision to its recommended payroll expense reduction to reflect the FTE count as of August 2014 as shown in the response to Late Filed Exhibit No. 55. Id., p. 52. Using the FTE count as of August 2014, which is 80 positions less than the June 1, 2014 FTE count, the OCC recommended a reduction to payroll expense of $5,575,188. Id.

In its Reply Brief, the OCC recommended that payroll expense be reduced by $5,547,165. OCC Reply Brief, (L&A-1), Schedule 1. The OCC stated that despite the Company's claim that it plans to fill the vacant positions, the evidence clearly indicated the current level of 4,253.8 FTEs is 182 FTEs less than the 4,435.8 requested. From December 31, 2013 through August 31, 2014, the employee count declined from 4,610.8 FTEs to 4,253.8 FTEs and that with the exception of June 2014, each month showed a steady decline in FTEs. Further, the evidence clearly shows that the decline is continuing, and despite the Company's claim that positions are being filled, the net result is that further reductions have occurred. OCC Reply Brief, p. 3.

The AG stated that it supported many of the other downward adjustments to CL&P's rate request that were proposed by the OCC in this matter including a downward adjustment to full time employees. AG Brief, p.23.

The Authority finds that it is highly unlikely for the Company to not have any type of vacancy rate when it determines its payroll expense costs for ratemaking purposes. The fact that the Company stated that some positions take much longer to fill than others is evidence that there are some open positions at any point in time.

In its Written Exceptions, the Company acknowledged the Authority's legitimate concern about the need for the Company to develop a vacancy rate. The Company suggested a vacancy rate of 1.5% which equates to a reduction in the requested FTEs of 66.5. The Authority determines based on its analysis of the evidence presented in the instant proceeding that a reduction of 147 FTEs is more appropriate.

Therefore, the Authority reduces the requested FTE total, through the following adjustments, relative to the 82 active positions as of September 5, 2014 and for the 100 positions which have yet to be approved. Late Filed Exhibit No. 54; Late Filed Exhibit No. 55, Attachment 2, p. 1.

b. 82 Active Positions

Of the 82 active positions, 50 are CL&P and 32 are NUSCO. Fifteen of the 82 positions are listed as being in the reviewing/interviewing/recruiting process and 32 positions are listed as being internal transfers/positions. The Authority determines that these 47 positions are speculative hires or if they are filled from within the organization, are a shifting of payroll dollars from one cost center to another and therefore, are disallowed. The Company's reluctance to track FTE statistics and develop vacancy rates concerns the Authority as it is an appropriate measure for any company to maintain, especially when justifying recovery of an FTE level in a rate proceeding.

Of the 47 FTEs that are disallowed, 28.2 FTEs (47 x 60%) will be reflected as CL&P positions using an average expense base salary of $97,924,[11] benefits loader of 46.2% of base salary and a payroll taxes loader of 8.5% of base salary as provided by the Company in Late Filed Exhibit No. 72. Forty percent or 18.8 FTEs (47 x 40%) are NUSCO positions which are then allocated to CL&P using the Company's allocation factor of 26.2%. The allocated NUSCO FTEs being disallowed are 4.9 FTEs (18.8 FTEs x 26.2%). The disallowed 4.9 NUSCO FTEs will be reflected using NUSCO's average base salary of $87,279,[12] a benefits loader of 46.2% of base salary and a payroll taxes loader of 8.5% of base salary as provided by the Company.

Therefore, the payroll expense adjustment is $1,467,954 as shown in the table below.

Table 19

ADJUSTMENTS FOR "ACTIVE" FTES			
		Disallowed FTEs	**Total**
CL&P FTE Adjustments			
Expense Adjustment for 28.2 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Expense (46.03%)	$45,074	28.2	$1,271,099
NUSCO FTE Adjustments			
Expense Adjustment for 4.9 FTEs	$87,279		
NUSCO Average Base Salary			
Base Salary Expense (46.03%)	$40,175	4.9	$196,855
Total Disallowed Payroll Expense		33.1	**$1,467,954**

c. 100 Positions to be Approved

The Company stated it is looking to fill 100 positions, which are at various stages of review in the Company's Human Resources organization and within the businesses. Late Filed Exhibit No. 55, p. 2. Of the 100 positions, 68 are for CL&P and 32 are for NUSCO. Id., p. 1. Also, the Company is continually reviewing these additional open positions to ensure that the positions that are approved, sourced and ultimate hired are reflective of the Company's needs. Id. The Authority maintains that it is uncertain whether these 100 positions, which have yet to go through the approval process, will ever come to fruition as positions that will be filled before the Rate Year. The Authority reiterates its concern regarding the lack of a vacancy rate in determining an expected FTE level. Moreover, the Company stated that there still may be merger synergies,

[11] The average base salary of $97,924 for CL&P employees is the average of the three employee class base payrolls for the rate year as presented in responses to Interrogatories OCC-185 and OCC-186 [($103,970+$102,821+$86,981)/3].

[12] The average base salary of $87,279 for NUSCO employees is the average of the three employee class base payrolls for the rate year as presented in responses to Interrogatories OCC-185 and OCC-186 [($96,098+$92,883+$72,865)/3].

which have yet to be determined and that it is always looking for ways to improve efficiencies. Tr. 9/12/2014, p. 2308. The Authority is of the opinion that the synergies would result in a decrease to FTEs rather than creating a need for an increase in FTEs. Consequently, the Authority disallows the 100 positions, 68 for CL&P and 32 positions for NUSCO. CL&P's 26.2% allocation of the NUSCO positions results in a disallowance of 8.4 FTEs. The disallowance of payroll expense for these positions is $3,402,526 as calculated in the table below.

Table 20

ADJUSTMENT FOR 100 POSITIONS YET TO BE APPROVED			
		Disallowed FTEs	**Total**
CL&P FTE Adjustments			
Expense Adjustment for 68 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Expense (46.03%)	$45,074	68.0	$3,065,060
NUSCO FTE Adjustments			
Expense Adjustment for 8.4 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Expense (46.03%)	$40,175	8.4	$ 337,466
Total Disallowed Payroll Expense		76.4	**$3,402,526**

d. Summary of Payroll Expense Adjustments

The total expense portion of payroll disallowed is $4,870,480. It represents a total of $1,467,954 for the active position disallowance and $3,402,526, which is the disallowance for the 100 positions yet to be approved.

e. Payroll Capitalization Adjustments

The Company capitalizes 53.97% of its payroll, which is the balance of payroll that is not expensed (100% - 46.03% expense). This capitalized portion is reflected in the Company's plant and rate base. It is necessary to adjust rate base for the portion of capitalized payroll that is being disallowed.

i. 82 Active Positions

The $1,721,170 of the disallowed capitalized portion of payroll for CL&P's 28.2 FTEs and NUSCO's 4.9 FTEs is calculated in the table below.

Table 21

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P FTE Adjustments			
Capitalization Adjustment for 28.2 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Capitalization (53.97%)	$52,850	28.2	$1,490,358
NUSCO FTE Adjustments			
Capitalization Adjustment for 4.9 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Capitalization (53.97%)	$47,104	4.9	$230,812
Total Disallowed Payroll Capitalization		33.1	**$1,721,170**

ii. 100 Positions to be Approved

The $3,989,449 of disallowed capitalized portion of payroll for the 68 CL&P FTEs and the 8.4 NUSCO FTEs is calculated in the table below.

Table 22

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P FTE Adjustments			
Capitalization Adjustment for 68 FTEs			
CL&P Average Base Salary	$97,924		
Base Salary Capitalization (53.97%)	$52,850	68	$3,593,772
NUSCO FTE Adjustments			
Capitalization Adjustment for 8.4 FTEs			
NUSCO Average Base Salary	$87,279		
Base Salary Capitalization (53.97%)	$47,104	8.4	$ 395,677
Total Disallowed Payroll Capitalization		76.4	**$3,989,449**

f. Summary of Payroll Capitalization Adjustments

The total capitalized portion of payroll disallowed is $5,710,619. It represents a total of $1,721,170 for the active position disallowance and $3,989,449, which is the disallowance for the 100 positions yet to be approved.

g. Payroll Taxes

As a result of the adjustments made to the Company's payroll, the Authority makes the associated adjustments to the Company's payroll taxes. Just as the Company has payroll that is expensed and payroll that is capitalized, so does the Company have both expense and capitalized portions of its payroll taxes.

i. Payroll Tax Expense Adjustment

The disallowed portion of payroll tax expense is $413,968 ($124,775 + $289,193) as a result of the 33.1 active FTEs which are disallowed and the 76.4 disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 23

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Payroll Tax Loader (8.5%)	$3,831	28.2	$108,042
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Payroll Tax Loader (8.5%)	$3,415	4.9	$16,733
Total Disallowed Payroll Tax Expense		33.1	**$124,775**

Table 24

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Payroll Tax Loader (8.5%)	$3,831	68.0	$260,508
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Payroll Tax Loader (8.5%)	$3,415	8.4	$28,685
Total Disallowed Payroll Tax Expense		76.4	**$289,193**

ii. Payroll Tax Capitalization Adjustment

The disallowed portion of capitalized payroll taxes is $485,390 ($146,300 + $339,090) for the 33.1 active FTEs which are disallowed and the disallowed 76.4 FTEs

for the 100 positions yet to be approved. The calculations are shown in the tables below:

Table 25

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 28.2 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Payroll Tax Loader (8.5%)	$4,492	28.2	$126,681
NUSCO Adjustments			
Capitalization Adjustment for 4.9 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Payroll Tax Loader (8.5%)	$4,004	4.9	$ 19,619
Total Disallowed Payroll Taxes Capitalization		33.1	**$146,300**

Table 26

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 68 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Payroll Tax Loader (8.5%)	$4,492	68.0	$305,456
NUSCO Adjustments			
Capitalization Adjustment for 8.4 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Payroll Tax Loader (8.5%)	$4,004	8.4	$ 33,634
Total Disallowed Payroll Taxes Capitalization		76.4	**$339,090**

h. Benefits

As a result of the adjustments made to the Company's payroll, the Authority makes the associated adjustments to the Company's benefits using the benefits loader of 46.2% of base salary as provided by the Company in Late Filed Exhibit No. 72. The adjustments include both the expense and capitalized portions of benefits.

i. Benefits Expense Adjustment

The disallowed portion of benefits expense is $2,250,146 ($678,190 + $1,571,956) as a result of the 33.1 active FTEs which are disallowed and the 76.4

disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 27

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Benefits Loader (46.2%)	$20,824	28.2	$587,242
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Benefits Loader (46.2%)	$18,561	4.9	$90,948
Total Disallowed Benefits Expense		33.1	**$678,190**

Table 28

EXPENSE ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Expense Adjustment for 28.2 FTEs			
Base Salary Expense (46.03%)	$45,074		
Benefits Loader (46.2%)	$20,824	68.0	$1,416,045
NUSCO Adjustments			
Expense Adjustment for 4.9 FTEs			
Base Salary Expense (46.03%)	$40,175		
Benefits Loader (46.2%)	$18,561	8.4	$155,911
Total Disallowed Benefits Expense		76.4	**$1,571,956**

ii. Benefits Capitalization Adjustment

The disallowed capitalized portion of benefits is $2,638,342 ($795,185 + $1,843,157) as a result of the 33.1 active FTEs which are disallowed and the 76.4 disallowed FTEs for the 100 positions yet to be approved. The adjustment is calculated as shown in the tables below:

Table 29

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 28.2 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Benefits Loader (46.2%)	$24,417	28.2	$688,561
NUSCO Adjustments			
Capitalization Adjustment for 4.9 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Benefits Loader (46.2%)	$21,762	4.9	$106,634
Total Disallowed Benefits Capitalization		33.1	**$795,185**

Table 30

CAPITALIZATION ADJUSTMENTS			
		Disallowed FTEs	**Total**
CL&P Adjustments			
Capitalization Adjustment for 68 FTEs			
Base Salary Capitalization (53.97%)	$52,850		
Benefits Loader (46.2%)	$24,417	68.0	$1,660,356
NUSCO Adjustments			
Capitalization Adjustment for 8.4 FTEs			
Base Salary Capitalization (53.97%)	$47,104		
Benefits Loader (46.2%)	$21,762	8.4	$ 182,801
Total Disallowed Benefits Capitalization		76.4	**$1,843,157**

i. Summary of Adjustments to Payroll Items

Following is a table summarizing both the expense and capitalization disallowance adjustments made to payroll, payroll taxes and benefits.

Table 31

ADJUSTMENTS	EXPENSE	CAPITALIZED
Payroll	$4,870,480	$5,710,619
Payroll Taxes	$413,968	$485,390
Benefits	$2,250,146	$2,638,342
Totals	**$7,534,594**	**$8,834,351**

j. Capitalized Expense Related Items - Depreciation

Based on discussions in Section II.C.2.i, Summary of Adjustments to Payroll Items and Section II.C.3.e, 401(k) and K-Vantage, the Authority reduces plant-in-service by $8,834,351 for capitalized payroll related expenses and by $185,595 for capitalized 401(k) expense and as a result, reduces depreciation expense. Using the composite depreciation rate of 2.56%, the Authority reduces depreciation expense by $230,911 [($8,834,351 + $185,595) *.0256].

3. Retirement Expense

a. Background

CL&P has a defined benefit pension plan that covers the majority of its existing employees. However, in 2006, CL&P closed entry to its defined pension benefit plan to newly hired non-bargaining employees. Effective January 1, 2006, the Company introduced a new enhanced 401(k)-based benefit called the K-Vantage Program for all new non-union hires and allowed existing employees to opt out with their pension frozen into the new benefit program. All new employees participate in the K-Vantage benefit instead of the defined benefit plan. Peloquin PFT, p. 13. For certain officers, CL&P offers a Supplemental Executive Retirement Plan (SERP) and Non-SERP plans, which are unqualified plans based on IRS rules. The Company offers retiree health care benefits for all retired employees.

a. Pensions

The pension expense is calculated on the basis of the accounting rules set forth in Accounting Standards Codification 715-30 (ASC 715-30). Response to Interrogatory FI-27. The pension expense is based on the following elements, which in total equal net periodic benefit cost.

Service cost
+ Interest cost
- Expected return on assets
+ Amortization of Unrecognized
(Gain)/Loss
Prior service cost
Transition Obligation (Asset)
Net Periodic Pension Cost

Generally, service cost is the increase in projected benefit obligation due to the accrual of benefits that occurred in the current period. Interest cost reflects the growth in present value of projected accrued benefit obligations as they come one period closer to payment. These costs are offset by the expected return on assets, which equals the fair market value of plan assets times the expected long-term rate of return on plan assets. To the extent these components deviate from actual or result from plan changes, the difference accumulates in asset or liability accounts and is amortized over a number of years into (gains)/losses, prior service cost, and transition obligation (asset). To the extent that actual and expected returns on plan assets are different, this is accumulated in unrecognized net (gains) or losses. Affecting each element of net periodic benefit cost are actuarial assumptions such as the discount rate, expected return on assets, and average wage increase.

CL&P requested the following for pension expense in its Application:

Table 32

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$47,213,000	($21,544,000)	$25,670,000

Application, Schedules C-3.27 and WPC-3.27d.

The above request was revised, due to a change in an actuarial assumption, to the following:

Table 33

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$47,213,000	($19,477,000)	$27,736,000

Late Filed Exhibit No. 3, Revised Schedule C-3.27.

CL&P's pension expense is a product of actuarial studies that determine the Company's liability to each pension plan participant, and include assumptions on salary increases, discount rate, and expected long-term rate of return on assets. The Company's actuary calculated actual pension expense to be $47,213,000 in the Test Year ended December 31, 2013, and projected expense of $27,736,000 in the Rate

Year ended 2015. The decrease in pension expense between the Test Year and the Rate Year of $19,477,000 is due to the amortization of net investment gains from 2010 through 2013, and an increase in the discount rate as calculated by the Company's actuary for the Rate Year. CL&P Brief, p. 41.

b. Other Post Retirement Employee Benefits

The Other Post Retirement Employee Benefits (OPEB) expense is calculated on the basis of the accounting rules set forth in Accounting Standards Codification 715-60 (ASC 715-60). Response to Interrogatory FI-15. This statement focuses principally on health care benefits, where the employer promises to provide health benefits after an employee retires. These benefits are grouped together under the name OPEB and the expense is calculated with one additional assumption from pensions which is the healthcare cost trend rate. This represents the expected annual rates of change in the cost of health care benefits currently provided by the post-retirement health care benefit plan.

CL&P requested the following for OPEB expense in its rate application:

Table 34

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$7,771,000	($3,829,000)	$3,942,000

Application, Schedules C-3.27 and WPC-3.27g.

The above request was revised, due to a change in an actuarial assumption, to the following:

Table 35

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$7,771,000	($3,710,000)	$4,061,000

Late Filed Exhibit No. 3, Revised Schedule C-3.27.

CL&P has been pro-active in controlling the growth of retiree healthcare costs through capping the Company's health care subsidies and changing plan designs for both pre-65 retirees and post-65 Medicare eligible retirees. Specifics are that for employees that have retired after 1991, the portion of the cost for medical coverage that is paid for by CL&P is capped at $6,101 per person under age 65 and $2,166 per person over age 65. This lower cap that applies for over age 65 retirees reflects the lower cost to CL&P as a result of retiree enrollment in the federal Medicare program, which is the primary coverage to these individuals. In addition to these limits, employees retiring after 1994 are responsible for additional premium payments based on a retirement age of less than 65 or service with the Company of less than 20 years.

These plan features serve to limit future growth in the Company's retiree health care expense. The portion of post-retirement health care expense associated with capped benefits has grown to 85% as of December 31, 2013. Peloquin PFT, p. 11.

Further efforts to reduce retiree medical expenses resulted in pre-65 retirees being transitioned to the same new medical designs as offered to active employees in 2013. This produced a shift in retiree enrollment in higher cost options toward lower premium and higher deductible options. CL&P reported that this shift is a result of default enrollment in the point of plan option (PPO)-90 plan and a comprehensive communications campaign. For the Test Year, more than 75% of retirees participated in the lower cost plans. Due to this shift to variable out of pocket costs, retirees are encouraged to become more educated about lower cost options in choosing providers and treatment plans which should result in mitigating health care cost inflation. Peloquin PFT, pp. 11 and 12.

Another area CL&P has worked to lower costs is prescription drug expenses. The Company has made significant plan design changes to the prescription drug benefit for Medicare-eligible retirees. In 2013, CL&P introduced a Medicare Part D employer group waiver plan (EGWP) through its pharmacy benefits manager. Retiree participation in the EGWP provides a lower cost as a result of offsetting payments from Medicare in the form of Part D direct subsidy payments, low income subsidies, pharmacy manufacturer reimbursements, and catastrophic reinsurance payments. These payments are returned to retirees, whose subsidy from the Company is capped, through lower monthly premium costs. For grandfathered retirees that do not pay monthly premiums, these payments are an offset to CL&P's cost. In addition, in 2013 the carrier was consolidated for the Medicare supplement and in 2014, the Company updated the plan design for Medicare eligible retirees. These changes eliminate non-Medicare coverage and applies the full Medicare Part B deductible on all participants. Peloquin PFT, p. 12.

In 2007, CL&P implemented a new Post-Employment Health Reimbursement Account (HRA) program, Med-Vantage that supplements benefits offered to employees in K-Vantage. The Company deposits $1,000 annually into a tax-advantaged HRA account for each participant who is age 40 or older, which can be used for post-employment healthcare premiums or expenses. Peloquin PFT, p. 14.

The Authority notes that the Rate Year 2015 expense is $3,710,000 less than the Test Year expense. The Authority's analysis indicates that this is due to investment gains and changes in the forecasted discount rate for 2015.

c. Actuarial Assumptions

The key actuarial assumptions used in determining the Company's pension and OPEB expense are: 1) discount rate; 2) expected return on assets; 3) average wage increase; and 4) health care cost trend rate. The discount rate is used to evaluate the present value of the plan liabilities. The higher the discount rate, the lower the present value resulting in a lower pension and OPEB expense. The expected return is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix. The higher the assumption, the more the plan

assumes it can earn resulting in lower pension and OPEB expense. The average wage increase is the assumed increase in annual wages for all employees in the plan. The higher the wage increase assumption, the higher the pension expense. The health care cost trend rate is comprised of an initial and ultimate cost trend rates, which is an estimate of future health care costs. The higher the health care cost trend rates, the higher the OPEB costs. The health care cost trend rate applies only to the OPEB Plan and not the pension plan

i. Discount Rate

The discount rate is the rate at which projected benefits are discounted back to a present value. It is used to evaluate the present value of the pension plan and OPEB plan liabilities. The Securities and Exchange Commission (SEC) requires the use of high quality bond yields to calculate the discount rate. In addition, the SEC has specified that discount rates should reflect the duration of a pension plan's liabilities. Response to Interrogatory FI-20.

The Company's actuary, Aon Hewitt (AH), used a yield curve methodology to calculate the discount rate for pension plan and OPEB plan liabilities. To develop its yield curves, AH uses hypothetical double A or greater yield curves represented by a series of annualized individual spot discount rates from 0.5 to 99 years. These spot rate curves are derived from a direct calculation of the implied forward rate curve based on the included bond cash flows. The forward rate curve is a continuous function and as such, this methodology allows the curves to be extended beyond the 30-year maturity period for which corporate bond data is generally available. This matches the IRS corporate bond yield curve methodology used for Employee Retirement Income Security Act (ERISA) funding calculations. Id.

AH used bond data and pricing information provided by Barclays Capital in constructing these yield curves. The bonds are screened to ensure that the resulting rates are consistent with relevant accounting standards and can be actually achieved by a pension or OPEB plan. Specific criteria used are as follows:

1. Each bond issue is required to have an average rating of double A when averaging all available ratings by Moody's Investor Services, Standard & Poor's and Fitch.
2. The universe of bonds includes only non-callable bonds so that the yield to maturity can actually be attained without intervening calls, puts or sinking funds.
3. To ensure marketability each constituent bond issue is required to have at least $250 million par outstanding.
4. Outlier bonds that have a yield to maturity that significantly deviates from the average yield within each maturity group are removed.

Id.

AH receives bond data, from Barclay's Bank, of approximately 6,000 bonds, which is effectively the data set underlying the Barclay's Aggregate Index minus U.S. Government and U.S Government related issuances. Approximately 1,000 bonds meet

the selection criteria for inclusion in the AH curves. On a monthly basis, AH produces the "AA Only Above Median" curve using this data which is calculated from a subset of bonds representing the 50% highest yielding bond issues within each defined maturity tranche of the AA only universe. Using this yield curve methodology, a discount rate of 5.03% was developed for the pension plan and a 4.78% discount rate for the OPEB plan. Id. The Authority is familiar with the yield curve approach and finds it is an acceptable methodology to calculate a discount rate for pension and OPEB expense.

CL&P stated that it will revise the discount rate on its pension and OPEB plans based on information from its actuary AH in the third quarter of 2014. Tr. 9/5/14, pp. 1496 and 1497. The Company submitted a worksheet developed by AH showing revised 2015 pension expense projections based on AA median yield curves**.** In addition, the Company submitted a worksheet developed by Towers Watson showing revised 2015 pension and OPEB expense projections. These work sheets show that interest rates have decreased by about 20 basis points from 4.45% to 4.26%. Using the most recent discount rates, calculated by AH, as of August 31, 2014, resulted in an increase to pension expense of $4.2 million and an increase to FAS 106 expense of $0.6 million. Late Filed Exhibit No. 40.

The Company revised the discount rate to a lower discount rate, at the direction of its actuary. CL&P used a discount rate of 4.26% as an input to calculate pension expense and a discount rate of 4.07% to calculate OPEB expense. Id.; Tr. 9/24/14, p. 2509.

The Authority analyzed the actuarial inputs that are used to calculate the discount rate and finds that the Company is correct in changing its discount rate. The discount rate was revised by CL&P due to changes in market conditions. Based on its analysis, the Authority approves the discount rate of 4.26% for the pension plan and 4.07% for the OPEB plan.

ii. Expected Return on Assets

CL&P developed the expected long-term rate of return assumption of 8.25%, for both the pension and OPEB plans, using input from actuaries, consultants, and economists. Data inputs come from long-term inflation and growth statistics for the economy. In addition, CL&P's expected long-term rates of return on plan assets are based on certain target asset allocation assumptions and expected long-term rates of return on those individual target asset allocations. The following shows the target asset allocation weights and the expected returns for each asset class.

Table 36

Asset Class	Target Weight	Target Returns
Equities		
US Equity	24.0%	9.0%
Non-US Equity	10.0%	9.0%
Emerging Markets	6.0%	10.0%
Fixed Income		
Fixed Income	15.0%	5.0%
High Yield Bonds	9.0%	7.50%
Emerging Market Bonds	6.0%	7.50%
Alternatives		
Hedge Funds	11.0%	7.00%
Real Assets	9.0%	7.50%
Private Equity	10.0%	13.00%

Response to Interrogatory FI-20.

Management at CL&P constructed the rates of return by asset category. These rates of return are based on management's best judgment using publicly available information regarding historical data, adjustments based on current market conditions, as well as their own experience and expectations. Based on this, CL&P management determined 8.25% should be used as the long-term rate of return on assets for the pension and OPEB plans.

A comparison of actual returns on pension plan assets to assumed rates of return on these same assets are as follows.

Table 37

Year	Actual Pension Plan Returns	Assumed Rate of Return
2013	15.0%	8.25%
2012	13.8%	8.25%
2011	2.0%	8.25%
2010	16.8%	8.75%
2009	25.0%	8.75%
2008	-31.1%	8.75%

Response to Interrogatory FI-34.

A comparison of actual returns on OPEB plan assets to assumed rates of return on these same assets are as follows:

Table 38

Year	Union Retiree Health Returns	Assumed Rate of Return
2013	16.2%	8.25%
2012	14.5%	8.25%
2011	-3.5%	8.25%
2010	15.9%	8.75%
2009	25.8%	8.75%

Response to Interrogatory FI-19.

CL&P stated that actual returns on pension plan and OPEB assets will differ from the long term rate of return assumption as a result of short-term market fluctuations. In addition, over the last five years following the 2008 financial crisis, return on plan assets have benefited from strong equity and credit markets. The strong performance of these markets explains most of the difference between the actual returns and the assumed long-term rate of return. Id.

When questioned on the validity of the 8.25% return on plan assets and whether this return should be increased for the Rate Year, the CL&P witness stated:

> Because we outperformed recently, I'd expect future returns to be less because it kind of goes back to a norm. So if anything, those higher numbers in recent years would tend to lower future expectations for rates. . . . . Not only that, my long-term rate of return is a long-term rate that is subject to review by the SEC, our auditors and our actuaries, and we do not know of any other company that is increasing their long-term rate of return and also I don't believe that our auditors would allow us to do that. We wouldn't have any support for it. Tr. 9/5/14, pp. 1498 and 1499.

The most recent return as of June 30, 2014, is reported as approximately 5%. Tr. 9/5/14, p. 1499. The Authority notes that the financial markets are subject to wide fluctuations and, therefore, recent returns may not be the norm for the future. The Authority finds that the assumed ROR of 8.25% for the pension and OPEB plans is reasonable based on the unpredictability of future returns.

iii. Average Wage Increase

The long-term average wage increase assumption is based on current salary increases, the level of promotions, and the level of increases reflected in the union contracts. A higher average wage increase would result in greater benefits earned by plan participants and thus would increase pension expense. The Company used an average wage increase assumption of 3% in its actuarial calculations. Response to Interrogatory FI-20.

A comparison of actual salary increases to assumed salary increases is as follows:

Table 39

Report Date	Year Over Year Change Average Pay	Salary Increase Assumption
2014	3.0%	3.5%
2013	3.0%	3.5%
2012	3.0%	3.5%
2011	3.0%	4.0%
2010	2.9%	4.0%

Response to Interrogatory FI-32.

Differences between the average pay increase and the salary increase assumption occur in every year. This is because the salary rate assumption is based on a long-term future pay increases rather than a one-year period of actual experience. Tr. 9/5/14, pp. 1499 and 1500. In any given year, salary can fluctuate based on overtime and commissions paid to participants in the plan. The Authority finds the 3% salary increase assumption to be reasonable.

iv. Healthcare Cost Trend Rate

The healthcare cost trend rate is an actuarial component of the retiree health care expense. There are two assumptions composing the healthcare cost trend rate, which is the initial assumption and the ultimate assumption. The initial assumption reflects expectations of health care cost increases for retirees in the near term. These increases are based on a number of factors including publically available general industry surveys, actual experience of the Company's retiree population, and experience of other large clients with post-retirement health care plans. The ultimate assumption methodology is developed from a building block methodology. Under this building block methodology, the underlying inflation assumption is established to reflect improvements in technology and additional utilization. In addition, the assumptions used in the valuation of the initial and ultimate trend rates are evaluated against those used by other general and utilities industry companies to ensure comparability. Response to Interrogatory FI-21.

The health care trend affects a decreasing number of older CL&P grandfathered retirees with an average age of 84. The portion of the NU OPEB obligation related to grandfathered retirees is less than 15% of the total plan obligation. As a result, the ultimate trend rate has very little impact given the short period of life expectancy. The remainder of the NU OPEB plan obligation relates to either retiree life insurance or health care for non-grandfathered retirees, which are subject to an employer cost cap. These obligations are not impacted by health care trend rates. In addition, post-65 retiree medical trends have been lower than active trends historically, particularly since unit cost is tied to Medicare allowable costs for the medical component. Id.

CL&P used an initial health care cost trend rate of 6.75% with an ultimate rate of 4.50%. These were developed using the following sources:

1. The 2014 Segal Health Plan Cost Trend Survey conducted in May and June of 2013 indicates that combined medical and Rx trend rates (increase in per capita claims) from 7.6 – 8.0% for PPOs and high deductible health plans (HDHP).
2. PwC's Health Research Institute (HRI) projected a 6.5% medical cost trend for 2014.
3. Sibson Consulting quoted 2014 projected medical trends ranging from 7.9% - 8.4% with Rx trend projected at a 6.3% increase.
4. CIGNA, the third-party administrator that manages the provider network, reported a combined medical and Rx trend of 9.42% for 2014.

Response to Interrogatory OCC-188.

In addition, when asked about whether there may be differences in parts of the country in medical trend rates, the CL&P witness stated that "New England typically is a very high cost area. It's because we have excellent facilities, a lot of very good employers and comprehensive health coverage." Tr. 9/5/14, p. 1507.

The Authority analyzed the above health care trend surveys and finds that they are reasonable. The Authority also finds that the initial health care cost trend rate of 6.75% with an ultimate rate of 4.50% is in the range of reasonableness and is an acceptable actuarial assumption to calculate the cost of the Company's OPEB plan.

v. Conclusion on Pension and OPEB Expenses

The Authority approves CL&P's revised requested pension cost of $27,736,000 for the Rate Year. The Authority concludes that CL&P applied the accounting rules set forth in ASC 715-30 correctly. The Authority finds the actuarial assumptions of discount rate, rate of return on plan assets, and wage increases to be reasonable. The Authority also approves CL&P's revised requested OPEB cost of $4,061,000 for the Rate Year. CL&P applied the accounting rules set forth in ASC 715-60 correctly. Further, the actuarial assumptions of discount rate, rate of return on plan assets, and health care trend rate are reasonable.

e. 401(k) and K-Vantage

A 401(k) plan is a qualified retirement plan under the Internal Revenue Code that allows employees to save a portion of their salary for retirement on a pre-tax basis. Typically, employers match a portion of each employee's contribution with the employee choosing the investment options for the contributions. The Company has two 401(k) plans which is a traditional 401(k) plan and the other an enhanced 401(k) called K-Vantage.

Participation in the K-Vantage program over the past five years has grown steadily. By the end of 2013, approximately 30% of CL&P and NUSCO employees were participating in K-Vantage compared to less than 20% in 2009. Peloquin PFT, p. 15. As of January 2006, the Company closed entry to its defined benefit pension plan to newly hired non-union employees. As an alternative these employees participate in an enhanced defined contribution benefit called K-Vantage. Under K-Vantage, in

addition to the traditional 401(k) match, the Company contributes an amount equal to a percentage of the employees covered pay into a 401(k) account. Peloquin PFT, p. 13. These contributions are based on the employee's age and amount of service which is as follows:

Table 40

Age plus Service	% of Covered Pay
Less than 40 years	2.5%
40 or more but less than 60 years	4.5%
60 or more years	6.5%

Peloquin PFT, p. 14.

The above percentages of covered pay were determined with the intent to produce the needed accrual to provide for a decent level of retirement. This is accomplished through the K-Vantage plan design such that the older an employee is, combined with increased years of service, an additional amount is added to the employee's plan. Tr. 9/5/14, p. 1525.

Non-union employees hired prior to 2006, were offered the opportunity to choose between continuing to earn benefits in the traditional defined benefit pension plan or to opt into the new K-Vantage plan. There were 2.6% of eligible CL&P employees and 7.8% of eligible NUSCO employees that elected to participate in K-Vantage. By 2009, all of the CL&P union employees had voted to participate in K-Vantage. All newly hired employees participate in the K-Vantage program. The Company reported that as is customary with defined contribution plan designs, CL&P employees bear 100% of the risk associated with their investment elections in the 401(k) and K-Vantage plans. Response to Interrogatory FI-6.

CL&P originally requested the following expense for its 401(k) plan which includes the K-Vantage expense:

Table 41

Test Year Expense 12/31/13	Pro Forma Adjustments	Test year Pro Forma	Rate Year Adjustments	Pro Forma Rate Year 2015
$4,391,000	$53,000	$4,444,000	$667,000	$5,111,000

Application, Schedules C-3.27 and WPC-3.27e.

The above request was revised due to a decrease in the NUSCO allocation to the following:

Table 42

Test Year Expense 12/31/13	Pro Forma Adjustments	Test year Pro Forma	Rate Year Adjustments	Pro Forma Rate Year 2015
$4,391,000	$53,000	$4,444,000	$543,000	$4,987,000

Late-Filed Exhibit No. 3, Revised Schedules C-3.27, WPC-3.27e.

CL&P reported that the conservation and load management employee expense was inadvertently included in allocated expenses reported for NUSCO employees. This amount was overstated by $141,000. Tr. 9/5/14, p. 1529; Response to Interrogatory OCC-190. The revised Test Year expense of $4,987,000 does not include the overstatement of $141,000.

The Authority looked for comparisons with other 401(K) programs from electric companies similar to CL&P to determine that the benefits being offered were within norms as the ratepayers fund the 401(k) plans. The Authority reviewed a detailed retirement plan benchmarking analysis prepared in April 2013 by Fidelity Investments as well as an industry benchmarking group survey that included a total of 14 like-sized utilities with revenues over $5 billion.[13] CL&P reported that the survey, last performed in 2013, shows total retirement value for new hires (which consists of 401k and K-Vantage program contributions only) ranks below median (approximately 90% of average) for the combined non-represented and union employees. Response to Interrogatory FI-5; Tr. 9/5/14, p. 1525. After analyzing both confidential studies, the Authority finds that CL&P's 401(k) and K-Vantage programs are within industry norms and reasonable.

CL&P asserted that it must attract and retain qualified employees. This is done through the benefits provided under CL&P's 401(k) Plan, which includes the K-Vantage program. Both are an important part of the total rewards program used to achieve this goal. Response to Interrogatory FI-7; Peloquin PFT, p. 3.

The OCC provided an adjustment to the 401(k) expense due to a payroll adjustment it made. The OCC stated that it employed the participation rate and average cost used by CL&P in its filing. The OCC calculated an adjustment of $132,000 on CL&P and for NUSCO, an adjustment of $129,000, for the Rate Year. The total 401 (k) adjustment, therefore, is $261,000 ($132,000 + $129,000). Schultz PFT, p. 18, Exhibit L&A-1, C-4; OCC Brief, p. 53.

CL&P took exception to the OCC's 401(k) adjustment. The Company stated that the OCC's methodology was based on a simplistic average. It does not account for the fact that CL&P's 401(k) plan costs are increasing as all new employees participate in this plan, rather than the defined benefit pension plan, which was closed to new employees as of January 2006. In addition, CL&P asserted that the OCC failed to recognize that the change in 401(k) expense is not linear based on historical data headcount or participation data. Future costs will be proportionally higher with each new employee due to the K-Vantage contribution (2.5%, 4.5% or 6.5%, based on age and years of service), which does not apply to employees who participate in the defined benefit pension plan. CL&P Reply Brief, p. 51.

[13] These studies were deemed to be proprietary and confidential.

The Authority recognizes how important qualified employees are to the overall goal of serving ratepayers for the Company. Given this, the Authority finds that the 401(k) and K-Vantage plans are useful in attracting and retaining qualified employees, which is a benefit to ratepayers. The Authority approves the Company's 401(k) and K-Vantage plans. However, for the Rate Year of 2015, the Authority finds an adjustment to the $4,987,000 401(k) expense is necessary due to the PURA's adjustment to payroll of $10,581,100 ($4,870,480 + $5,710,619) See, Section II.C.2.i Summary of Adjustments to Payroll Items, Table 31.

To adjust the 401(k) expense based on the Authority's adjusted payroll, the PURA used CL&P's methodology. Based on eligibility requirements and employee participation in the 401(k) and K-Vantage Plans, the Company reported that its contribution percentage can range anywhere from 0% to 6.5%. Therefore, an average contribution rate of 3.25% (6.50%/2) is used as a proxy. Response to Interrogatory FI-119.

The Authority calculated the adjustment to the 401(k) expense as follows:

Table 43

Description	Amount	Calculation
Change in Payroll	($10,581,100)	
Company Average Contribution to Employees 401(k) Plans	3.25%	
Change in 401 (k) Expense (pre capitalized basis)	($343,886)	($10,581,100) * 3.25%
Amount Capitalized	($185,595)	($343,886) * 53.97%
Net Change in CL&P's 401 (k) Expense	($158,291)	($343,886) – ($185,595)

Based on the above calculation, the Authority approves a 401(k) expense of $4,828,709 ($4,987,000-$158,291).

f. Supplemental Executive Retirement Plan

A SERP, which is a non-qualified plan, provides executives with a supplemental retirement benefit in addition to the benefit provided under the qualified plan. CL&P reported that it is a common company practice to provide executives with a benefit that makes them whole for the limits on pensionable earnings that the IRS imposes on qualified pension plans. The objective is for executives to receive a pension that is similar to nonexecutives' pensions relative to their pay. Response to Interrogatory FI-44. CL&P reported that there are 34 current employees eligible for SERP benefits when they retire. There are 51 retired employees and/or spouses currently collecting SERP benefits. There will be no new participants in the SERP because CL&P no longer offers a defined benefit pension plan to new employees. The SERP complies with section 409A of the IRS Code. Responses to Interrogatories FI-43, FI-45, FI-46, and FI-48.

In its Application, the Company requested the following for SERP anticipated expenditures.

Table 44

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$1,680,000	$359,000	$2,039,000

Application, Schedules C-3.27 and WPC-3.27f.

CL&P stated that the Rate Year adjustment of $359,000 is due to pre-capital adjustment for NUSCO, which included allocated NSTAR costs in the rate year expense. This adjustment was partially offset by the discount rate which increased by 79 basis points from the Test Year to the Rate Year from 4.24% to 5.03%. Response to Interrogatory FI-169. The Company did not change its requested SERP expense based on a decrease in the discount rate for the rate year of 2015, which would have meant an increase in the SERP expense. Tr. 9/24/14, pp. 2509 and 2510.

The OCC opposed the Company's SERP expense in its rate case. The OCC defined SERP "as an additional retirement plan, provided to a select few employees, to increase their retirement compensation beyond what the IRS allows in a qualified plan." Schultz PFT, p. 45. The OCC's reasoning to exclude the SERP expense is based on the points cited below:

1. The SERP is available to only those employees that are already highly compensated. Therefore these highly compensated employees move even farther ahead of most of their fellow employees.
2. Employees that receive SERP benefits are already members of CL&P's regular retirement plan.
3. The SERP costs are for employees that are retired and therefore no longer providing service to ratepayers.

Id.

The OCC argued that in the 2009 CL&P Rate Case, the Authority allowed the SERP expense but with two caveats. The first was that the Authority would not authorize recovery from ratepayers of any SERP expense for employees hired after January 1, 2006. Secondly, the Authority recognized that SERP expense should not increase in the future since the SERP benefits are existing costs for the majority of those retired or inactive employees hired prior to 2006. Schultz PFT, p. 46.

The OCC's analysis shows that the SERP expense has increased significantly from the 2009 CL&P Rate Case in which CL&P included SERP costs of $1,282,000 in the first rate year and $1,277,000 in the second rate year. In the instant proceeding, the Company has $1,680,000 in the Test Year with a further increase of $359,000 in the Rate Year. The OCC argued that for an expense that should not have increased, the "jump" from $1,277,000 in the 2009 CL&P Rate Case to $2,039,000 is egregious. Schultz PFT, p. 47.

The OCC recommended a SERP adjustment to remove the entire $2,039,000 from the Rate Year. The OCC believes that this adjustment is consistent with the Authority's ruling in the Decision dated June 30, 2009 in Docket No. 08-12-06, Application of Connecticut Natural Gas Corporation for a Rate Increase. In that Decision, the Authority disallowed all costs related to both the Energy East Corporation SERP and the Excess Plan. However, if the Authority were to allow a portion of the SERP expense, the OCC recommended the removal of costs above $1,277,000, as the 2009 CL&P Rate Case stated that costs should not increase, which would be a reduction of $762,000 ($2,039,000 - $1,277,000). Id. The OCC stated that it is not recommending that the SERP be discontinued, but that CL&P's shareholders, not the ratepayers, pay for the costs. OCC Brief, p. 76.

The OCC also recommended that in conjunction with the removal of SERP costs, the offset to rate base for the SERP reserve, net of accumulated deferred income taxes, be removed, which would increase rate base by $2.128 million. The OCC made this adjustment but noted that only a portion of the net reserve be adjusted since ratepayers have funded the cost and are entitled to be credited for advancing those funds. Schultz PFT, pp. 47 and 48, Exhibit L&A-1, Schedule C-7; OCC Brief, p. 77.

The AG asserted that the Authority reject CL&P's proposal to collect any SERP expense from ratepayers, which would result in a reduction in revenue requirements of $2.0 million. The AG cited the Authority's June 30, 2009 Decision in Docket No. 08-12-06 and the Decision dated July 17, 2009 in Docket No. 08-12-07 Application of The Southern Connecticut Gas Company for a Rate Increase, where the Authority disallowed SERP expense based on the poor economy. AG Brief, pp. 17 and 18.

CL&P advocated that the SERP expense benefits ratepayers since it is necessary for the Company to offer a compensation and benefit package that correctly compensates executives with particular experience, skills and qualifications. These executives have a range of employment opportunities due to their skill levels that carry with them a certain level of compensation and benefits. As such, it becomes necessary for CL&P to offer SERP benefits to these individuals to attract them to the Company. These executives hold positions with a relatively substantial amount of responsibility and manage the work of many other employees. Hiring qualified executives is important to customers since these individuals' decisions affect a range of matters pertaining directly to the cost and quality of utility service provided to customers. Response to Interrogatory FI-49.

CL&P stated that the Authority consistently has allowed recovery of its SERP expense recognizing that the costs are "common practice among companies with qualified defined benefit pension plans." 2009 CL&P Rate Case Decision, pp. 64 and 65. In addition, CL&P cited the January 22, 2014 Decision Docket No. 13-06-08, finding that SERP expense "is an appropriate expense of doing business." CL&P Brief, pp. 49 and 50.

CL&P took exception to the OCC and AG argument to disallow SERP costs. The Company stated that the OCC and AG recommendation to disallow CL&P's costs for the SERP conflicts with established PURA precedent and the 2009 CL&P Rate Case Decision, which allowed recovery of these costs. The Company notes that while the

OCC and AG argues that the disallowance of SERP costs was supported by the June 30, 2009 Decision in Docket No. 08-12-07, CL&P asserts that they neglected to mention that the SERP ruling in that Decision was overturned by the January 2014 Decision in Docket No. 13-06-08, which allowed recovery of SERP costs. Tr. 9/5/14, pp. 2039 and 2040. In addition, the Company argued that the OCC's argument is flawed when requesting a cap on the recovery of SERP costs at $1,277,000 based on language in the 2009 CL&P Rate Case Decision. CL&P Reply Brief, pp. 50 and 51.

The Authority analyzed the SERP actuarial statements and finds them to be acceptable. Protected Response to Interrogatory FI-47. The SERP expense is driven by the actuarial discount rate. The Company testified that the change in the discount rate affected the SERP as it did pension and OPEB expense; however, the Company did not reflect the change in the discount rate as an increase in the SERP expense. The Company indicated that it does not update the SERP expense as frequently as the pension and OPEB expense. Tr. 9/24/14, p. 2509.

The Authority notes that the OCC's witness acknowledged that the Decision language on which he relied did not refer to cost changes that could occur due to active employees covered by the SERP. Tr. 9/5/14, pp. 2035 and 2036. The witness asserted that the SERP is for employees no longer providing service to the Company. However, during cross-examination, he admitted that the plan also includes active employees and that costs could change from year to year due to changes in the number of active employees. Tr. 9/5/14, pp. 2035 and 2036, 2039. The Authority determines that the 2009 CL&P Rate Case capped the SERP expense at $1,277,000 in the second rate year and the $1,282,000 in the first rate year relates only to the number of employees entering the SERP. It does not relate to the actuarial calculation of the discount rate, which is a major component of the SERP expense. The SERP expense is capped based on the fact that no new employees after January 1, 2006, are allowed in the SERP but that expense can change based on actuarial calculations. This is evident from the language in the 2009 CL&P Rate Case, which stated the following:

> The Department understands that it has been common practice among companies with qualified defined benefit pension plans to provide executives with this additional benefit, however, with the introduction of the new enhanced 401(k) plan known as the K-Advantage Program, any officers hired after January 1, 2006 will no longer be eligible to participate in SERP. The Department recognizes that the SERP expenses should not increase in the future since the SERP benefits are existing costs for the majority of those retired or inactive employees hired prior to 2006. Therefore, the Department will allow the costs associated with the existing SERP benefits as it has in past rate cases, however, the Department will not authorize the recovery by ratepayers of any SERP expenses for those hired after January 1, 2006.
>
> 2009 CL&P Rate Case Decision, pp. 63 and 64.

The Authority finds that the SERP expense should be recoverable by the Company for the same reasons as stated in its last rate case. The SERP has been a common practice among companies with qualified defined benefit pension plans to

provide executives with this additional benefit. The Authority approves the SERP expense of $2,039,000 since it is based on an actuarial calculation.

g. Non-Supplemental Executive Retirement Plan

The Non-SERP account is used to record expenses related to specially negotiated post-employment benefits, including pension enhancements not covered by the NUSCO Retirement Plan or the SERP. Such enhancements are normally provided in the hiring agreements to make up for benefits lost at previous employers by some mid-career hires or as part of a separation agreement with NU. As with SERP, Non-SERP benefits have been necessary to retain some qualified personnel and as a special retention arrangement. Tr. 9/5/14, pp. 1533 and 1534.

The Authority finds that this retention of employees benefits ratepayers since it produces a well-run company. Currently, there are 60 current or former CL&P and NUSCO employees whose expense is recorded in the Non-SERP account. Response to Interrogatory FI-122. CL&P has provided a Non-SERP benefit to one employee that was hired after January 1, 2006. This Non-SERP benefit included separation benefits as part of the individual's employment agreement and continuation of certain health benefits. CL&P recorded no expense amount included in the Rate Year for any of the Non-SERP costs associated with this individual. Response to Interrogatory FI-123.

The Non-SERP is a non-contributory plan. The benefit payments that are made to participants are first contributed from CL&P to the trust and then the funds are immediately disbursed to participants. Response to Interrogatory FI-121. There were no NUSCO employees participating in the Non-SERP hired after January 1, 2006, and therefore, the Non-SERP expense does not reflect any changes allocated to CL&P from NUSCO. Response to Interrogatory FI-124. In its Application, the Company requested the following to reimburse for Non-SERP anticipated expenditures.

Table 45

Test Year Expense 12/31/13	Rate Year Adjustments	Pro Forma Rate Year 2015
$1,203,000	($300,000)	$903,000

Application, Schedules C-3.27 and WPC-3.27g.

The Company did not change its requested Non-SERP expense in the Rate Year despite changes in the discount rate. Tr. 9/24/14, pp. 2509 and 2510.

The OCC opposed the Company including its Non-SERP expense of $903,000 in its rate case. This expense is comprised of $230,000 of CL&P expense and $673,000 of NUSCO allocated costs. Schultz PFT, p. 48. The OCC recommended the removal of the entire Non-SERP expense of $903,000. However, the OCC is not recommending that Non-SERP benefits be discontinued but that these costs be borne by shareholders. Schultz PFT, p. 50. The OCC defined Non-SERP as additional pension plans that go beyond the Company's regular retirement plan and the SERP as well. The Non-SERP expense relates to individually negotiated post-employment benefit agreements.

Schultz PFT, p. 48; OCC Brief, p. 77. The OCC argued that it is not appropriate for ratepayers to be responsible for this Non-SERP retirement package expense since it is beyond what most of CL&P's employees receive and beyond what most ratepayers receive, if they do in fact have retirement packages at all. Schultz PFT, p. 49.

The OCC noted that there is only one active employee and 60 retirees from CL&P and NUSCO receiving Non-SERP benefits, which is a reason ratepayers should not be responsible for these costs. Since the majority of the Non-SERP expense relates to former employees, it is obvious that ratepayers are not receiving current benefits from these costs. Id. The OCC also recommended that, as part of the adjustment to remove Non-SERP costs, CL&P's reserve offset to rate base, net of accumulated deferred income taxes, be removed. This would result in an increase to rate base of $406,000. The OCC made this adjustment and suggested that an argument can be made to keep the reserve as an offset to rate base because ratepayers have funded this expense and as such, should be credited for that funding. Schultz PFT, p. 50.

CL&P claimed that the Authority previously approved Non-SERP expenses since it is a benefit to employees that are a "common practice among companies with qualified defined benefit pension plans" as stated in the 2009 CL&P Rate Case Decision, pp. 64 and 65; CL&P Brief, pp. 41 and 42.

The Authority, in the 2009 CL&P Rate Case, stated the following:

> As with SERP benefit costs, Non-SERP benefits currently exist for those employees hired prior to January 1, 2006 and were part of the hiring agreements to originally retain those employees. The Department understands that this Non-SERP plan is a form of a post-employment or pension enhancement benefit, so it is only logical that the majority of these employees have since retired or become inactive. The Department does not find it fair to terminate recovery of an existing benefit that has been allowed recovery in the past.
>
> 2009 CL&P Rate Case Decision, p. 65.

The Authority also allowed the Non-SERP benefit in the Company's rate case in the Decision dated January 28, 2008, in Docket No. 07-07-01, Application of CL&P to Amend Rate Schedules.

The Authority analyzed the actuarial statements on the Non-SERP in the response to Protected Interrogatory FI-9 and finds them to be acceptable. The Non-SERP expense is driven by the actuarial discount rate. The Company testified that the change in the discount rate affected the Non-SERP as it did the pension and OPEB expense; however, the Company did not reflect the change in the discount rate as an increase in the Non-SERP expense. The Company indicated that it does not update the Non-SERP expense periodically throughout the year as is the practice for the pension and OPEB expense. Tr. 9/24/14, p. 2509. The Authority approves CL&P's Non-SERP cost of $903,000 since it is an ongoing expense and should be recoverable by the Company.

h. Allocations to CL&P from Subsidiaries on Retirement Benefits

Allocations from NUSCO are made through direct charges to the operating company that benefitted from the charge whenever possible. When costs cannot be identified as being provided to one specific company or business segment, or when direct charging is not otherwise feasible, cost allocation methodologies are used. Late Filed Exhibit No. 36. These methodologies vary with the business unit, department and cost control center. The allocation of costs for NUSCO employees is based on the NUSCO employees' total payroll, both directly charged and allocated through the use of the NUSCO charging account unit (CAU) 99 allocation rate budgeted for each year. This is referred to as the 9C allocation for the Test Year and rate C7 for the Rate Year. Responses to Interrogatories FI-152, FI-153, FI-154, FI-155, and FI-156.

The Authority approves the allocation of pension, OPEB, SERP and Non-SERP costs for NUSCO employees to CL&P based on the Authority's review of the calculations of the 9C allocation for the Test Year and rate C7 for the Rate Year. The Company's allocation methodology, for retirement benefits, is consistent with cost allocation methodologies used in prior rate cases. However, the NUSCO 401(k) cost allocated to CL&P was changed due to changes on NUSCO payroll allocated to CL&P.

Northeast Nuclear Energy Company (NNECO) is a subsidiary of NU and was the agent for Northeast Utilities system companies as well as other New England utilities in operating and maintaining the Millstone Nuclear Generation facilities. NNECO pension and OPEB expenses are allocated to CL&P based on CL&P's 81% ownership of NU's share of the Millstone units prior to their sale. This is based on the 2009 CL&P Rate Case Decision which stated that, "[t]he Department concurs with CL&P's 81% allocation of the NNECO pension costs, and finds them properly recovered in CL&P's total pension and OPEB expense." 2009 CL&P Rate Case Decision, p. 61.

The Authority approves the allocations to CL&P from NNECO for pension and OPEB expenses since this was the intention in the Authority's Decision in Docket No. 99-09-12, Application of The Connecticut Light and Power Company and The United Illuminating Company for Approval of Their Millstone Nuclear Generation Assets Divestiture Plans. In the subsequent Millstone purchase and sale agreement, the Authority required CL&P to be responsible for the NNECO pension and employee benefit costs with CL&P's share calculated at 81% of the pension and OPEB costs.

i. Capitalization

CL&P capitalized a portion of its retirement benefits expense into rate base. To the extent that employees are doing capital work, a portion of their benefits and pension costs are capitalized along with their direct labor costs. The Company indicated that the amount of pension expense that is capitalized is based on the payroll that is capitalized. The actual capitalization amounts recorded on the Company's books reflect an allocation of employee benefits, payroll taxes and insurance to expense and capital consistent with how payroll was distributed and recorded in the Test Year. Responses to Interrogatories FI-8, FI-99, FI-103, FI-110, FI-111, and FI-118. The Authority

reviewed the Company's capitalization calculations and made certain adjustments See Section II.D.3.c Capitalized Expense Related Items.

j. Consultant/Actuarial Fees

CL&P requested $310,000 for consulting/actuarial fees on Schedule C-3.27 for both the Test Year and Rate Year. This is broken down as follows:

Table 46

Vendor Name	Description	($000's)
AON/Hewitt and Associates	Actuarial Services for the Pension Plans	$149
Towers Watson/Perrin	Actuarial Services for the OPEB Plans/ Benefit Consulting Services	$602
Fiondella, Milone, & Lasaracina LLP	Consulting Services/ Benefit Audits	$230
	Total NUSCO Billing	$981
	Total Percentage Allocated to CL&P Distribution	31.55%
	Total Amount Allocated to CL&P Distribution (Schedule 3.27)	$310

Response to Interrogatory FI-51.

The history of this expense is shown by the following:

Table 47

Description	2008	2009	2010	2011	2012
Actuarial Services for the Pension Plans	$91,000	$86,000	$124,000	$66,000	$123,000
Actuarial Services for the OPEB Plans/ Benefit Consulting	$591,000	$455,000	$472,000	$320,000	$238,000
Consulting Services/ Benefit Audits	$64,000	$64,000	$63,000	$70,000	$33,000
Total CL&P Distribution Expense	$746,000	$605,000	$659,000	$456,000	$394,000

Response to Interrogatory FI-151.

The actuarial and benefit consultant expenses are for costs allocated from NUSCO based on different allocator rate codes. CL&P determined that the 31.55% should be a blended rate derived from the 99 allocator rates, and not reflect the other allocators used to allocate costs in the Test Year. CL&P provided its calculation showing how the 31.55% was derived along with a calculation by individual rate code that is more indicative of how these costs were actually allocated in the Test Year.

Response to Interrogatory FI-50. The Authority analyzed the calculation and finds it is correctly done and appropriate.

The Authority does not have an issue with this expense since it has been trending downward. Based on the Authority's experience and judgment, $310,000 seems reasonable and hereby approves CL&P's $310,000 request for actuarial/consulting expenses.

4. Rate Case Expense

The Company requested $1.5 million for rate case expenses associated with the current proceeding, which would be amortized over a seven-year period. Schedule WP C-3.34, p. 3. This cost is approximately $1.3 million more than the rate case expense of $211,000 in the Company's previous rate case. The $1.5 million includes $100,000 for an ROE witness, $350,000 for a depreciation witness, $500,000 for legal services, $300,000 for the OCC's consultants, $100,000 for other external costs and $150,000 for incremental costs. Response to Interrogatory OCC-169, p. 1.

The OCC initially recommended a reduction to rate case expense of $560,000 and an annual amortization expense of $80,000. The OCC stated that ratepayers should only be responsible for prudently incurred costs and these costs are excessive. The OCC recommended that the ROE witness costs be reduced by $60,000, the depreciation witness costs reduced by $200,000, legal fees reduced by $250,000 and the OCC fees reduced by $50,000. OCC Brief, p. 74. The OCC stated there is nothing to demonstrate that the Company produced a more thorough or informative application as a result of this dramatic increase in rate case expense. Id. The OCC also claimed that throughout this docket, the Company has repeatedly failed to meaningfully respond to relevant discovery and that CL&P failed or refused to provide its cost of service study, evidence requested regarding incentive compensation, approval of capital expenditures and system resiliency spending among other items. Id.

Subsequently, the OCC recommended that the entire rate case expense be disallowed. OCC Reply Brief, p. 9. The OCC reiterated that CL&P repeatedly denied it access to documents requested in discovery. Id. CL&P then attempted to use some of the documents that it failed to provide to impeach the very witnesses who had requested those documents and that this type of gamesmanship should not be tolerated. Id.

The AG did not address the rate case expense specifically. Rather, it stated that the Authority should make the adjustments proposed by the OCC. AG Reply Brief, p. 11. The Company did not address the issue of rate case expense in either its brief or its reply brief.

The Authority considers the requested rate case expense to be unjustified. The projected expense for the Rate Year is an increase of 611% [($1,500,000-$211,000/$211,000] over the 2009 CL&P Rate Case. The Authority disallows $510,000 of the requested $1.5 million as follows: the ROE witness costs should be reduced by $60,000; the depreciation witness costs reduced by $200,000; and the legal fees

reduced by $250,000. The allowed costs of $990,000 ($1,500,000 - $510,000) provide for a substantial increase when compared to the 2009 CL&P Rate Case.

The amortization period for the allowed costs of $990,000 will be four years rather than the seven years requested by the Company. The Authority determines that the seven-year amortization is excessive, considering the Company will be filing another rate case in 2017. Moreover, in its last rate case, the Company recovered the $211,000 rate case expense in one year. Typically, the Authority has allowed amortization periods for rate case expense from three-five years. As a result, the annual amortization expense for rate case expenses increases to $248,000 per year from the $214,000 proposed by the Company.

5. Residual O&M

Residual operation and maintenance (O&M) expense represents the portion of Test Year expenses that CL&P specifically did not analyze based on the size of the dollar amounts involved. Mahoney PFT, p. 44. The Authority typically allows utilities a residual O&M expense category since, without this adjustment, a utility would not be made whole for increases in its O&M expenses not adjusted for elsewhere.

Specific analysis of CL&P's original residual O&M request shows total Test Year O&M expenses, for the Test Year ended December 31, 2013, of $381,729,000. From these total Test Year O&M expenses, CL&P determined $2,513,000 to be Test Year residual O&M expenses. CL&P originally requested a Test Year pro forma adjustment of $1,005,000 which provides for a rate year residual O&M expense request of $3,518,000 ($2,513,000 + $1,005,000). Schedule WPC-3.31. CL&P revised its residual O&M expense request due to an accounting error that was discovered during this proceeding. The Test Year expense of $2,513,000 remained the same. A Test Year pro forma adjustment was made of $2,122,000 for a rate year pro forma expense of $4,635,000 [$2,513,000 + $2,122,000]. Response to Revised Interrogatory FI-40; Late Filed Exhibit No. 3; Revised Schedule C-3.31; Revised Schedule WPC-3.31.

The Company reported that the residual O&M expenses shown on Schedule C-3.31 generally exclude all significant fixed and contractual expenses. Almost all fixed and contractual expenses are material in nature and therefore would be captured in a specific C schedule. Response to Interrogatory FI-36. CL&P reported that Test Year total operating expenses were charged to over 500 accounts and sub-accounts. For purposes of this proceeding, CL&P employed the following steps to ascertain the most material expenses and specific adjustment to those:

1. For CL&P Distribution and NUSCO, costs allocated to CL&P Distribution Test Year expenses were broken down into cost control center (CCC) levels by direct costs.
2. CL&P then analyzed activities and sub activities to determine the different groupings of costs that would be presented on specific C Schedules for the Test Year.
3. CL&P analyzed these activities and sub activities to determine the nature of the expense, identify significant changes that affected the Test Year, and to estimate the rate year level of expense. This analysis further refined the

categorizing of common expenses for rate case schedules of various expenses such as insurance, telecommunications, depreciation, etc.
4. Expenses determined to be unrelated to the major categories of expenses or immaterial on a stand-alone basis then became a residual O&M expense.
5. CL&P continued to revisit various expense adjustments as needed to ensure that the residual amount was at a level that was considered reasonable given the amount of Test Year expenses and representative of a Rate Year level.

Response to Interrogatory FI-39.

During cross-examination the Company witness outlined the accounting process to ensure that the residual expenses are not included in other C schedules expense accounts. Tr. 9/24/14, pp. 2470 and 2471.

In its original filing, the Company made pro forma adjustments of $1,005,000 to the residual O&M expenses which are detailed in the following:

1. In March 2013, CL&P made an accounting adjustment correction of $1.442 million for storm costs that were not properly coded. This correction was made in the Company's test year in Account No. 593.
2. In April 2013, the State of Connecticut reimbursed CL&P $2.553 million for an overpayment of the State Economic Recovery Reduction Bonds. The Company removed this credit from the test year since it is a one-time credit adjustment in Account No. 930.
3. In December 2013, CL&P recorded $106,000 in payments in error. In January 2014, these payments were corrected.

Response to Interrogatory FI-40; Mahoney PFT, p. 44.

The Company, upon further review of its residual O&M expenses, stated that it found an error in its accounting. The pro forma adjustment of $1.442 million was done in error in the Test Year. Response to Revised Interrogatory FI-40. In addition, to the net credit of $1.442 million, CL&P found an offsetting debit, which resulted in no impact to the Test Year ended December 31, 2013. As such, the Company now indicated it should not have adjusted its residual O&M expenses by $1.422 million in its original filing. Revised Response to Interrogatory FI-114.

The accounting entries for the derivation of the $1.442 million, for storm expenses, are as follows:

Table 48

Month	Account No.	$ Amount	Description
March 2013	59306	1,441,500	Transfer to Reserve
March 2013	59306	(2,576,300)	True-up of Deferred Storm Balance
March 2013	59306	(2,039,000)	True-up of Deferred Storm Balance
March 2013	59306	108,300	True-up of Deferred Storm Balance
March 2013	59306	246,200	True-up of Deferred Storm Balance
March 2013	59306	2,819,300	True-up of Deferred Storm Balance
Total		$1,441,500	

Revised Response to Interrogatory FI-114, Attachment 1.

The journal entry for the $1,441,500 is as follows:

Table 49

Account No.	Account Description	Debit	Credit
59306	Overhead lines, distribution and maintenance (OH Distr Mntc A)	$1,441,500	
182SU	Contra – 182ST		$1,441,500
Total		$1,441,500	$1,441,500

Revised Response to Interrogatory FI-114, Attachment 1, p. 2.

The purpose of the above journal entry was to record the reserve for incremental deferred costs related to true-ups to the five deferred storms recorded in March 2013. Revised Response to Interrogatory FI-114, Attachment 1, p. 2; Tr. 9/5/14, p. 1461.

The derivation of the net total of the adjustment for the State Economic Recovery Reduction Bonds is as follows:

Table 50

Date	Account No.	Amount	Description
April 2013	93099	($2,553,000)	Reverse Reserve on CL&P Etc. - 04/13
December 2013	90800	$74,000	CL&P Corporate Relations Advertising Account (Corp Rel Acct)
December 2013	90800	$1,000	CL&P Corp Rel Acct
December 2013	90800	$26,000	CL&P Corp Rel Acct
December 2013	90800	$4,000	CL&P Corp Rel Acct
December 2013	90800	$1,000	CL&P Corp Rel Acct
Total		($2,447,000)	CL&P Corp Rel Acct

Revised Response to Interrogatory FI-40, Attachment 1, p. 1.

When questioned why the residual O&M expense request increased from its original application, the Company witness stated that it was due to a credit of ($2.477) million in residual O&M for the economic recovery bonds as a result of over payment by the state of these bonds. The credit came back from the State of Connecticut to CL&P

and as such the Company needed to remove that credit. CL&P took the Test Year amount and increased it by ($2.477) million. Tr. 9/24/14, pp. 2490 and 2491.

The Authority recognizes the revision of CL&P's journal entries resulted in an increase in residual O&M expense. After analyzing CL&P's revised journal entries, the Authority finds the journal entries to be correct.

CL&P's request of residual O&M expense does not reflect an inflation factor. It did not use an inflation factor to determine its residual O&M expense for the Rate Year based on the 2009 CL&P Rate Case Decision. This Decision allowed CL&P to recover Test Year expenses only. Response to Interrogatory FI-39.

In addition, since this is the first rate case filed approximately two years after its merger with NSTAR, it has not included an inflation factor on residual O&M expenses due to merger-related savings. It is the Company's expectation that merger related savings would be achieved within the first five years following the merger, which was reflected in the net benefit analysis at the time. As such, the exclusion of an inflation factor in this five–year time period is consistent with the expectations from the merger. Response to Interrogatory FI-117.

CL&P discovered several accounts that were included in residual O&M expenses that should not have been:

Table 51

FERC Account No.	Account Name	Amount
90500	Miscellaneous Customer Account Expense	$143,167
921105	Office Expense Building	$63,819
Total		$206,986

Late Filed Exhibit No. 39.

The Company also reported that $106,000 was incorrectly charged to CL&P. In the Company's analysis of the Test Year residual O&M expenses, it was discovered that these costs were for the low income special needs program payable to the Boathouse Group in December 2013. These costs should have been recorded to the Systems Benefit Charge (SBC) and CL&P corrected the accounting in January 2014. An analysis of bank records shows the breakdown of these costs as follows:

Table 52

$ Amount	Payment Reference No.
780.98	038147500000
4,269.33	138147500000
26,032.50	256747500000
929.88	338147500000
73,909.90	828147500000
$105,922.59	

Response to Interrogatory FI-147.

CL&P removed these accounts totaling $312,909 ($206,986 + $105,923) from the Test Year residual O&M expenses. The Authority agrees that these accounts should be excluded from the residual O&M.

The Authority examined the Company's residual O&M expenses for certain accounts that historically should not be included as a residual O&M expense. CL&P's witness stated that these expenses (i.e., non-industry dues and memberships, scholarships, charitable contributions and expenses for holiday parties) have been excluded from the residual O&M expenses. Tr. 9/5/14, pp. 1475 – 1478. The Authority's analysis indicates that these expenses are not included in the residual O&M.

The summary of changes the Company made to their original residual O&M expense request is as follows:

1. A decrease of $119,000 for officer's expenses included in the Company's Test Year.
2. Removal of a pro-forma adjustment for $1.442 million that was inadvertently adjusted. At the time of the Company's filing, it was unaware of an offsetting credit that was recorded in the Test Year as well.
3. A decrease of $207,000 for miscellaneous costs included in the Company's Test Year.

Late Filed Exhibit No. 3.

The Authority analyzed changes to the residual O&M expense of a Test Year pro forma adjustment amount of $2.121 million. These changes include a decrease of $119,000 in officer's expenses and a decrease of $207,000 in miscellaneous costs. The Authority approves these changes as filed in Late Filed Exhibit No. 3. The Authority examined the group of accounts totaling $4,635,000 for the pro forma rate year. The Authority's analysis focused on the contents of each individual account, whether the expenses were adjusted elsewhere in the Application, and whether these expenses would be recurring. The Authority finds that all the accounts that represent the residual O&M expenses of $4,635,000 are approved as a residual O&M expense. CL&P has excluded various accounts from the residual O&M expenses and are not in the total of the $4,635,000 residual O&M. Based on the Company's adjustments, the

Authority has no further adjustments to the revised residual O&M expense of $4,635,000.

6. Board of Directors Expense

The Company included $583,000 in its Application for the Board of Directors (BOD) expense. CL&P stated that its share of the Rate Year BOD expense is a legitimate business expense that should be recovered in rates. CL&P Reply Brief, p. 63.

The OCC recommended that the BOD expense be reduced by 75% because the role of the Board of Directors is to protect the interests of the Company's shareholders and ratepayers receive little, if any, benefit from this expense. OCC Brief, p. 78. The OCC noted that the January 22, 2014 Decision in Docket No. 13-06-08:

> …that the same 75/25 sharing of this expense between shareholders and ratepayers is appropriate and consistent with recent Board of Director's expense adjustments made in Decisions issued by this Authority.

The OCC stated that the Company provided BOD meeting minutes that were redacted to the point where the vast majority of text had been blackened out and that the BOD's activities were not transparent or open to the Company's customers and regulators. For this reason, the OCC recommended that the entire costs for the BOD be charged to shareholders as a below-the-line cost and removed from revenue requirements. Id.

The Authority finds that the main objective of the BOD is to protect the interest of the Company's investors or shareowners. Ratepayers may indirectly benefit from the activities of the BOD; however, ratepayers are not the focus of the BOD decisions. Consistent with the determinations in previous Decisions regarding BOD expense and Directors' and Officers' Liability Insurance (DOL) expense, the Authority allows only 25% of BOD costs in rates. Hence, the allowed BOD costs are $145,750 ($583,000 x 25%) and the disallowed costs are $437,250 ($583,000 - $145,750).

7. Directors' and Officers' Liability Insurance

CL&P requested $467,000 for DOL insurance expense. The Company stated that DOL is a legitimate business expense of publicly traded corporations because it protects directors and officers from lawsuits brought by shareholders, including unmeritous and frivolous lawsuits. CL&P Reply Brief, p. 61. Also, no one would serve on a board of directors of a publicly traded corporation without such insurance. Id. Furthermore, CL&P stated that the OCC failed to identify a single publicly traded corporation that does not purchase DOL insurance for its directors and officers and for that and the other stated reasons, the Authority should reject the OCC's requested reduction. Id.

The OCC agreed that DOL protects the officers of the Company from lawsuits brought against them by shareholders that arise as a result of decisions that they make while performing their duties. Therefore, the shareholders, who receive the payout, are

the primary beneficiaries of this insurance. Ratepayers receive very little of the benefit and should not be responsible for all of the costs. OCC Brief, p. 75. The OCC noted that the Company failed to recognize that many legitimate expenses (e.g., image building advertisements, lobbying expenses) are not recoverable. Id.

The OCC recommended the disallowance of the entire expense of $467,000. However, if the Authority determines that the costs should be shared, the OCC recommended a 75/25 split between shareholders and ratepayers respectively, a reduction of $350,000. Id., p. 76. The OCC also stated that this adjustment is consistent with the Decision in Docket No. 13-06-08. Id.

The AG indicated that the Authority should reject CL&P's request to have ratepayers fund 100% of the Company's DOL insurance and, consistent with the Authority precedent, allow no more than 25% of this cost be allocated to ratepayers. AG Brief, p. 16.

The Authority finds no convincing reason to deviate from its previous treatment of DOL insurance. Consistent with the determinations in previous Decisions regarding BOD expense and DOL expense, the Authority will allow only 25% of DOL costs in rates. Therefore, $116,750 of DOL expense will be funded by ratepayers ($467,000 x 25%). This results in a DOL insurance expense decrease of $350,250 ($467,000 x 75%).

8. Healthcare Expense

The Company originally requested an increase of $4.5 million related to employee healthcare benefits expense for a total requested amount of $22.3 million for the Rate Year. Schedule C-3.27. During the proceeding, the Company revised the requested increase to $4.21 million for a revised total of $22.0 million. Schedule WPC-3.27a-Revised. The reduction in the expense is a result of an increase in the capitalization portion of healthcare benefits.

The Company stated that the increase to healthcare insurance expense is necessary to recover the normal escalation in healthcare costs based on industry data, and is consistent with the trend adjustment allowed in CL&P's last rate case. CL&P Brief, p. 37. The Company claimed that the increase is less than would have occurred without the redesign and marketing effort of employee benefit programs that was undertaken following the merger of NU and NSTAR. Id. The Company further stated that the increase was determined in collaboration with Strategic Benefit Advisors (NU's health and welfare employee benefits advisor), CIGNA healthcare (NU's health plan partner) and other trend survey data. Id., p. 38. The Company uses a self-funded program design and the escalation rate experienced between 2013 and 2014, and anticipated between 2014 and 2015 reflects growth in the cost of medical care and prescriptions (healthcare inflation) and the added cost of compliance with the Affordable Care Act. Id.

The OCC asserted that CL&P simply escalated the Test Year amount in its determination of healthcare costs and that this approach is incorrect because the Company has a self-funded plan and healthcare costs are claims driven. OCC Reply

Brief, p. 5. The OCC further stated that the Company claims that 2013 measures was a one-time cost savings are disingenuous, considering the CL&P witness agreed that the increase in employee contributions that took effect in 2013 would continue and that the CL&P escalation of 13.85% ignores the savings achieved through increased employee cost sharing. Id. Additionally, the OCC claimed that the Company's reference to this escalation being supported by a collaborative effort is also disingenuous. Specifically, considering the fact that CL&P acknowledged the three industry expert studies provided in response to OCC-188 were generic and not CL&P specific, and that the CIGNA documentation was not included. Id.

The OCC expressed concern that the documents supposedly relied upon by the Company in estimating its healthcare cost in the Application are dated subsequent to when the Late Filed Exhibit was requested at the September 8, 2014 hearing. Id., p. 6. The OCC stated that this "evidence" in support of the Application, developed after the fact, should be rejected. Id. The OCC initially recommended a reduction in healthcare expense of $3.3 million based upon an average historical increase per employee and the recommended FTE count. Id. The OCC revised its recommended adjustment to a reduction of $3.014 million to the Company's requested health care cost of $22.002 million, as a result of its revision to the FTE count for payroll and the changes made by the Company in Late Filed Exhibit No. 3. Id.

The AG did not address healthcare costs specifically, but it supported many of the other adjustments requested by the OCC to CL&P's rate request. AG Brief, p. 23.

CL&P stated that the OCC's recommended disallowance of $3.3 million is based on a skewed analysis and that it rejects industry data as well as expert guidance provided to the Company by its health and welfare employee benefits advisor. CL&P Reply Brief, p. 48. Moreover, the Company asserted that the OCC's witness calculated an average annual increase of just 6.64%, which is well below the Company's actual experience and medical trend rates for 2014 and 2015. Id. Lastly, the Company indicated that its trend increases of 7.75% in 2014 and 8% in 2015 were developed based on a minimum of four sources of information to which it applied industry-accepted underwriting guidelines and its own claim experience. Id.

Based on the evidence the Company provided, the Authority accepts the Company's proposed healthcare costs increases of 7.75% for 2014 and 8% for 2015. The Authority reduces the total employee benefits expense by $2.25 million based on its reduction of 109.5 FTEs as discussed in the Payroll section of this Decision.

9. Employee Incentive

CL&P's Test Year non-executive incentive compensation expense was $7.8 million. Application, Schedule C-3.28. The total non-executive incentive compensation expense requested for the Rate Year is $10.38 million. Id. The Company excluded executive incentive compensation expense of $8.7 million from the Application and is not seeking its recovery. Judge PFT, p. 11; Application, Schedule C-3.29. The Company stated that it limited the rate year costs to the variable compensation paid to operations and staff employees up to the director levels, whose goals and performance metrics under the post-merger program promote reliability, service quality and higher

levels of customer service, among other improvements. CL&P Brief, p. 35. Also, its variable pay program is designed to drive performance improvements and operational excellence through the use of detailed metrics that may be applied across positions within the same, or across all job scopes. CL&P Brief, p. 34.

The OCC recommended disallowing the entire non-executive incentive compensation expense of $10.38 million for the Rate Year. OCC Brief, p. 60. The OCC stated that the inclusion of a portion of incentive compensation in above-the-line expenses paid for by ratepayers is appropriate only if the plan actually provides incentive to improve performance. OCC Brief, p. 56. The OCC stated that the Company's effort to emphasize how the plan focuses on customer goals as justification for the appropriateness of the cost is simply a "smoke screen." Schultz PFT, p. 22; OCC Reply Brief, p. 7. The OCC noted that the overall financial trigger to when a payout can be made is earnings per share and all incentive funding is based on an NU financial metric. The fact that the net income goal is the primary goal while customer service-related goals are of less importance, should be taken into account in determining the funding level, if any, that should be made by ratepayers. Id. In addition, the OCC stated that CL&P did not provide sufficient necessary metrics to establish that its incentive plan is indeed effective. The information that was provided strongly suggests otherwise. The OCC also claimed that the Company did not provide details of goals and results nor did it provide any evidence that goals have been raised. Id., p. 60.

The AG recommended that the Authority eliminate the entire $10.38 million from the Company's proposed revenue requirements and from rates. AG Brief, p. 17. The AG stated that CL&P's proposed incentive plans are generally designed to incent and achieve goals, such as profit levels, that benefit the Company's shareholders, not its ratepayers. Thus, ratepayers should not be forced to fund incentive plans that benefit only the Company, especially when so many Connecticut ratepayers are in difficult economic circumstances. Id. In addition, the AG stated that the Company's incentive program does not appear to be structured to provide any "incentive." Rather the Company's "incentive" plan appears to be a base compensation measure under another name therefore, ratepayers should not be forced to pay "incentive" compensation that is neither at risk nor designed to benefit the ratepayers. Id.

The Authority recognizes the importance of incentivizing employees to achieve higher standards of customer service and other goals. The Authority also acknowledges the fact that the Company did not provide compelling evidence illustrating the metrics under which incentive compensation would be achieved. The evidence the Company presented indicates that over the past 6 years, 99.7% of eligible employees received incentive compensation. Response to Interrogatory OCC-101. This suggests that the Company's incentive compensation plan is more an extension of its base compensation plan than a true incentive compensation plan.

The Company stated in its Written Exceptions that its new variable pay program is designed to drive performance improvements and operational excellence through the use of detailed metrics and therefore the Authority should allow the total requested non-executive incentive compensation of $10.38 million.

The OCC in its Written Exceptions maintains that the Company failed to provide sufficient evidence to support its claim that it has changed its incentive compensation metrics to improve performance and to focus on customer goals. Further, the OCC stated that the existing plan does not provide a true incentive for employees to achieve higher standards of customer service and other goal. OCC Written Exceptions, pp. 37 and 38.

The Authority finds that the Company's evidence in this proceeding is minimal at best. The metrics provided for incentive compensation were for one employee and one type of position. Response to Interrogatory OCC-375. The Company claimed that more emphasis is placed on customer service and customer goals. Lazor PFT, p. 23. It fails to acknowledge that its incentive compensation metrics dealing with SAIDI and CAIDI are more a function of the increase in capital expenditures on system hardening and resiliency and less a function of employees' actions.

The Authority finds that incentive compensation expenses should not be borne solely by the ratepayers. The costs should be shared by both ratepayers and shareholders. Therefore, based on an analysis of the evidence presented in the instant proceeding and consistent with its recent Decision dated September 24, 2013 in Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut to Amend Its Rates and in its Decision dated January 22, 2014 in Docket No. 13-06-08, Application of Connecticut Natural Gas Corporation to Increase Its Rates and Charges the Authority disallows 50% of the total requested non-executive employee compensation for a total disallowance of $5.19 million.

10. Public Liability Expense

The Company included $4,765,000 of public liability expense for the rate year. The Test Year public liability expense was $1,955,000. The initial proposed rate year expense is an increase of $2,810,000 ($4,765,000 - $1,955,000) over the Test Year. Subsequently, in Late Filed Exhibit No. 63, the Company revised its public liability expense downward to $3,972,438 based on updated report from its actuary. Reply Brief, p. 57.

The OCC initially recommended a reduction of $2,112,400 to the public liability expense. This is the difference between the requested amount of $4,765,000 and the average of public liability expense for the years 2009-2013 of $2,652,600. OCC Brief, p. 79. The OCC later revised its recommendation based on the Company's adjustment in Late Filed Exhibit No. 63. The OCC's revised recommendation was a reduction of $752,585. This is the difference between the Company's revised requested amount of $3,972,438 and the 5-year average of $2,652,600 multiplied by the revised allocation to O&M of 57.05%. OCC Reply Brief, p. 9.

CL&P stated that its Rate Year expense is supported by an actuary that calculated the expense level based on the most recent information available about the Company's public liability losses and exposures. CL&P Reply Brief, p. 57. The Company contended that the OCC's recommendation is not supported by an actuary and that it is based on an unsupported opinion that CL&P's level of expense in the Rate

Year should merely be an average of the expense it incurred over the past six years. Id., p. 58

Based on the updated actuarial information presented by the Company in Late Filed Exhibit No. 63, the Authority determines that the requested amount of $3,972,438 is reasonable and therefore no adjustment to the public liability expense is made.

11. Facilities Rent Expense

CL&P reported $9.527 million as the rent expense for the Test Year and proposed $8.726 million for the Rate Year. The internal rent expenses are $7.18 million for the Test Year and $6.499 million for the Rate Year. The external rent expenses are $2.348 million for the Test Year and $2.226 million for the Rate Year. The $802,000 total proforma adjustment consists of reductions of $680,000 for internal and $122,000 for external rent expenses. The Company indicated that the $680,000 reduction to the internal rent expense is to remove $623,000 associated with property at 56 Prospect Street in Hartford and $57,000 associated with the closure of facilities through consolidation. Similarly, the $122,000 proforma adjustment for external rent expense is due to the closings of facilities through consolidation. Schedules C.3.19 and WP C-3.19; Mahoney PFT, p. 39.

a. NSTAR Corporate Office

As part of the total external rent expense proposed for the Rate Year, CL&P included $203,269 as its portion of the rent expense for the NSTAR Corporate office in Boston, Massachusetts. In accordance with the determination in Docket No. 09-12-05, CL&P did not include $622,939 representing its allocated amount for the 56 Prospect Street, Hartford Corporate Office. Response to Interrogatory AC-85 Attachment 1, p. 1.

Concurrent with its determination regarding the Hartford Corporate Office, the Authority opines that the NSTAR Corporate office should not negatively impact costs recoverable from CL&P's ratepayers. The Authority finds that CL&P failed to support the need for the allocated Boston corporate office space. As such, CL&P's ratepayers should not be responsible for the additional corporate office rent cost resulting from the NU//NSTAR merger. Such mergers should create cost savings from operation and management synergies and not increased operating costs for the regulated entities within the new holding company. Therefore, the Authority will reduce the Company's proposed external rent expense by $203,269.

b. NUSCO Internal Rent Expense

For facilities under the management of Rocky River Realty (RRR), the NU real estate subsidiary, internal rent expense consists of such costs as interest, depreciation, property tax and equity return expenses. CL&P indicated that the total internal RRR rents are allocated based on Test Year budgeted total payroll costs for NUSCO's employees. The Company testified that charge accounting unit (CAU) 99 allocation rates are used for direct and allocated RRR's rent expense. Response to Interrogatory AC-85, Attachment 1, pp. 1-5.

For purposes of this proceeding, the Authority focuses its analysis concerning the total internal RRR rent allocated to CL&P distribution on amounts from the Berlin Campus; 3333 Berlin Turnpike Building; and Windsor Customer Service (Windsor CS) facilities (together, RRR Facilities). For the Berlin Campus, the total rent expense for the Test Year was $8,578,534, of which $4,047,520 was allocated to CL&P. Response to Interrogatory AC-85, Attachment 1, p. 2. For the 3333 Berlin Turnpike Buildings, the total rent expense for the Test Year was $1,290,971, of which $710,109 was allocated to CL&P. Id., p. 4. For the Windsor CS facility, the total rent expense for the Test Year was $3,818,745, of which $1,651,607 was allocated to CL&P. Id., p. 5.

The internal rent expenses for the RRR Facilities are allocated in stages. The first stage involves allocation based on the total square footages occupied by the NU operating companies and by NUSCO. The second stage involves the apportionment of the total operating companies' and NUSCO's portions of the total rent amounts to the operating companies. The Company stated that the allocation factors for cost control centers (CCC) 048, 06F and 121 are used to allocate the total operating companies' portions of the total rent expenses for the RRR Facilities to the operating companies. The CCC 141 factors are used to allocate NUSCO's portion of the total rent expense to the operating companies. Response to Interrogatory AC-85, Attachment 1, pp. 1-5; Late Filed Exhibit No. 75, Attachment 3. Based on the CCC 141 allocation, 43.25% was used to allocate NUSCO's portion of total rent expense for the RRR Facilities to CL&P distribution and this percentage was shown on the work paper for CCC 1NR. Id.; Late Filed Exhibit No. 74; Response to Interrogatory AC-85, Attachment 1, pp.1-5; Schedule G-2.16 Attachment, p. 873.

Based on the following analysis, the level internal rent expense allocated to CL&P distribution as its share of the NUSCO's portion of total rent expense is overstated and the calculation of this allocation factor is flawed.

i. Equity Return

The return on equity (ROE) used to calculate the equity return costs included in the total rent expense for each of the RRR Facilities is 9.92%. Late Filed Exhibit No. 75 Attachment 1, p. 6. Ratepayers should not pay cost of capital to the Company's affiliates in an amount above the ROE allowed for CL&P in this proceeding. The equity return costs included in the total rent expense should reflect CL&P's allowed ROE in the instant proceeding. For the Berlin Campus, the Company calculated total rent expense of $8,578,534, which includes total equity cost of $3,996,782. Late Filed Exhibit No. 74, Attachment 1, p. 2. For the 3333 Berlin Turnpike Buildings, the Company calculated total rent expense of $1,290,971, which includes total equity cost of $602,726. Id., p. 4. For the Windsor facilities, the Company calculated total rent expense of $3,818,745. This amount is 99% of the total rent expense for Windsor CS because 1% was attributed to the Connecticut Valley Exchange (CONVEX). The total equity cost for Windsor CS is $1,800,458. However, only $1,782,453 ($1,800,458 x 99%) was included in the total rent expense allocable to CL&P. Id., p. 5.

Based on the allowed ROE herein, the Authority determines that the equity return costs to be included in the total rent expenses for the Berlin Campus is $3,694,606 ($3,996,782 / 9.92% x 9.17%); for the 3333 Berlin Turnpike Buildings is $557,157

($602,726 / 9.92% x 9.17%); and for the Windsor CS is $1,647,691 ($1,782,453 / 9.92% x 9.17%). Therefore, the Authority will reduce equity return costs included in the total facility rent expense by $302,176 ($3,996,782 - $3,694,606) for the Berlin Campus; $45,569 ($602,726 - $557,157) for the 3333 Berlin Turnpike Buildings; and $134,762 ($1,782,453 - $1,647,691) for the Windsor CS facilities. Consequently, the total rent expenses subject to direct and indirect allocations are $8,276,358 ($8,578,534 - $302,176) for the Berlin Campus, $1,245,402 ($1,290,971 - $45,569) for the 3333 Berlin Turnpike Buildings, and $3,683,983 ($3,818,745 - $134,762) for the Windsor CS facilities.

ii. NUSCO'S Allocation to CL&P

The Company stated that the NSTAR shared service company has been merged into NUSCO effective January 1, 2014. CL&P is now allocated costs from the former NSTAR service company and, similarly, NUSCO costs that were formerly allocated to CL&P and other NU affiliates are now allocated to NSTAR operating companies consistent with cost causation principles. Furthermore, the post-merger NUSCO reviewed its allocations to all the operating company affiliates, and that the actual cost allocation factors have changed. However, the overall allocation of service company costs has not generally caused a change to the amounts allocated to CL&P from the new NUSCO. Mahoney PFT, p. 49.

The Authority concludes that the 43.25% used to allocate NUSCO's portion of the total RRR facilities rent expense to CL&P distribution is excessive and based on an allocation factor that is without any causal effect on CL&P's use of these facilities. The Authority reviewed the 2013 Annual Report for Centralized Service Companies (Form No. 60) that NUSCO filed with the Federal Energy Regulatory Commission (FERC). Response to Interrogatory AC-20, Attachment 3. The report shows that approximately $59.874 million of the $468.84 million was billed to NSTAR Gas and Electric. The CL&P portion of the 2013 total shared cost was $252.358 million. Id., p. 307. Also, the report indicated that costs for facilities floor space should be allocated based on the projected square footage occupied. Id., Note Page 402.1. Furthermore, in the 2009 CL&P Rate Case Decision, the Company was directed to continue determining facility rent expense for CL&P based on the square footage directly charged or allocated to it, unless it could show a change in the amount of square footage needed by the distribution segment. 2009 CL&P Rate Case Decision, p. 40.

For the instant proceeding, the Company continues to use the 9C allocator that is based on NUSCO's employee labor costs and not on square footage to allocate internal rent expense to CL&P. According to the Company, the CCC 1NR allocator mirrors 9C and is based on NUSCO budgeted labor costs and does not allocate costs to NSTAR companies. Late Filed Exhibit No. 75, Attachment 4, p. 2. The Authority determines that the 9C allocator is flawed because it is based on NU legacy costs and does not take into consideration the labor costs for the NSTAR service company, which is now merged into NUSCO. More poignant to the point that the 9C allocation is faulty is the fact that the Company reported, for allocating NUSCO's costs, CCC 048 factors that are based on square footage of the Berlin Campus using the C7 allocators. Under the C7 allocation, the total CL&P distribution allocation factor is 32.94% and NSTAR's factor is

32.53%, not zero as reported under the 9C allocation, which was based on pre-merger assumptions and non-correlating labor costs. Schedule G-2.16 Attachment, p. 218.

The Company indicated that the facilities management costs for CCC 136 are allocated using the C7 Rate Code factors. These allocators are based on the new NUSCO's budgeted labor costs for both NU and NSTAR affiliates. Further, the CL&P distribution has an allocation factor of 26.95% under the C7 formula. Schedule G-2.16 Attachment, p. 608. The Company did not provide overall allocators based on the C7 Rate Code showing the total allocated rent factors for the 3333 Berlin Turnpike Buildings and Windsor CS facilities. Therefore, the Authority determines that the C7 allocation percentage of 26.95% is more appropriate than the C9 allocation percentage of 43.25% for allocating NUSCO's portion of the total rent expenses for the 3333 Berlin Turnpike Buildings and Windsor CS facilities to CL&P distribution. The C7 allocator mirrors the 9C allocator, with the exception that it is based on the new NUSCO's budgeted labor costs, not NU legacy labor costs solely based on old NUSCO costs. In its response to inquiry as to how NUSCO's 401K costs are allocated, the Company stated that the "costs are allocated based on how NUSCO employees total payroll, both directly charged and allocated through the use of CAU 99 allocation rate, is budgeted each year. This is referred to as the 9C allocation for the Test Year and rate C7 for the projected rate year." Response to Interrogatory FI-152. For the CL&P distribution allocation, the Company indicated that the 9C percentage for the Test Year is 43.25% and the C7 percentage for the Rate Year is 26.20%. Response to Interrogatory FI-152, Attachment 1, pp. 1 and 2. However, CL&P used the 9C and not the C7 allocator to determine the proposed rent expense for the Rate Year in this proceeding.

Using the C7 allocator of 26.95% for 3333 Berlin and 43.25% Windsor CS facilities for CL&P's portion of the new NUSCO's portion of the total rent expense, the Authority calculates the allowed rent expenses for the RRR Facilities as summarized in the table below:

Table 53
Calculations of the Allowed Rent Expense for RRR Facilities

	3333 Berlin Buildings	Windsor CS Facilities
Revised Total Rent Expense	$1,245,402	$3,683,983
Allocated to Operating Companies14	$ 258,047	$ 0
Portion Allocated to CL&P Distribution15	$ 258,047	$ 0
Total Rent Allocated to NUSCO16	$ 987,355	$3,683,983
Portion Allocated to CL&P Distribution17	$ 266,092	$1,593,323
Total Portions to CL&P Distribution	$ 524,139	$1,593,323

As shown in the table above, the Authority calculates allowed rent expenses of $524,139 for the 3333 Berlin Buildings and $1,593,323 for the Windsor CS facilities. Therefore, the Authority will reduce the proposed facility rent expenses by $185,970 ($710,109 - $524,139) for 3333 Berlin Buildings and $58,230 ($1,651,553 - $1,593,323 for the Windsor CS facilities.

The Company stated that the Proposed Final Decision contains a mathematical error that understates CL&P's portion of the rent expense for the Berlin Campus by $470,655. According to the Company, the $2,726,232 rental expense apportioned to CL&P in the Proposed Final Decision, calculated by multiplying $8,276,358 by 32.94%, failed to take into consideration a charge of $934,688, the CL&P portion of rental expense for the Berlin Campus directly allocated to the operating companies by RRR. The Company stated that the correct total rental expense attributable to CL&P for the Berlin Campus is $3,196,887. CL&P Written Exceptions, pp. 46-48. Thus, according to the Company, the adjustment in the draft is overstated by $470,655 ($3,196,887 - $2,726,232). Id., p. 48.

The Company is confused with the Authority's use of an overall allocation factor of 32.94% to derive the portion of the adjusted total rental expense of $8,276,358 attributable to CL&P. The C7 allocator utilized by the Authority is a combined factor that takes into consideration both the square footages directly allocable to the operating companies and the square footages allocated to NUSCO, which are indirectly allocated to all applicable operating companies. Schedule G-2.16 Attachment, p. 218. In the Proposed Final Decision, the Authority established that NUSCO should allocate cost to CL&P based on the C7 factor of 26.20% and that NUSCO's portion of total rental expense should be allocated to CL&P based on the C7 allocator of 26.95% applicable to facilities management costs. Based on the C7 allocator of 26.95%, the Authority determined that CL&P's portion of the Berlin Campus rent allocated to NUSCO is $1,850,819 ($6,867,602 x 26.95%). Thus, the total rental expense allocable to CL&P

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14 Operating Companies directly occupy 20.72% of 3333 Berlin Turnpike Buildings' and 0% of Windsor CS's total square footages. Late Filed Exhibit No. 74 Attachment 1, pp. 4 and 5,

15 100% of total square footage occupied by Operating Companies is allocated to CL&P distribution. Late Filed Exhibit No. 74 Attachment 1, p. 4,

16 NUSCO directly occupies 79.29% of 3333 Berlin Turnpike Buildings' and 100% of Windsor CS's total square footages. Late Filed Exhibit No. 74 Attachment 1, pp. 4 and 5,

17 Based on Rate C7 allocation percentage of 26.95% for 3333 Berlin and the C9 rate of 43.25% for Windsor CS Facilities.

for the Berlin Campus is $2,785,507 ($934,688 + $1,850,819). The rental expense adjustment in the Proposed Final Decision is overstated by $59,275 ($2,785,507 - $2,726,232) as compared to the Company's claim of $470,655. Consequently, the Authority disallows rent expense $1,262,013 ($4,047,520 - $2,785,507) for the Berlin Campus.

The Company also indicated the Authority made a mathematical error in the Proposed Final Decision by changing CL&P's share of the cost of the Windsor CS facilities from 43.25% to 26.94%. The 43.25% allocation factor does not allocate any portion of the cost of the Windsor facilities to NSTAR; whereas the 26.94% allocation factor allocates a portion of the Windsor facility's cost to NSTAR. According to the Company, the Windsor CS facilities do not handle any calls for NSTAR's customers; and the Westwood, Massachusetts Customer Care Facility handles calls for NSTAR's customers and does not handle any calls for CL&P's customers. Therefore, NSTAR should not pay for a portion of the Windsor Customer Care facility rent expense. According to the Company, using the allocation factor of 26.94% instead of 43.25% understated CL&P's portion of the rent expense for the Windsor CS facilities by $600,338. CL&P's Written Exceptions, pp. 48 and 49.

Based on the record, the Authority agrees that the Windsor CS facilities currently does not handle calls for NSTAR affiliated companies. As a result, the Authority agrees and recalculated the rental expense adjustment for the Windsor CS facilities as detailed in the table above. The final reduction to the proposed rental expense for the Windsor CS facility is $58,230 ($1,651,553 - $1,593,323).

The total disallowed internal rent expense for the RRR Facilities is $1,506,213 ($1,262,013 + $185,970 + $58,230). Including the disallowed external rent expense of $203,269, the total disallowed allocated facility rent expense is $1,709,482 ($1,506,213+ $203,269).

12. NUSCO Capital Funding

The Company stated that NUSCO Capital Funding expense is the money that NUSCO requires to fund certain capital investment that support shared services. That expense is shared among all NU subsidiaries using the shared capital investments. CL&P indicated that the Rate Year adjustment is due to a change in NUSCO's actual 2013 payroll capital/expense allocation. The change caused an increase to the NUSCO capital funding expense of $402,000. CL&P reported $2.701 million as the NUSCO Capital Funding expense for the Test Year and proposed $3.103 million for the Rate Year. Schedule WP C-3.16. The NUSCO Capital Funding expenses are net of the capitalized portions of $0.805 million for the Test Year and $0.424 million for the Rate Year. Id. Thus, the total NUSCO capital funding expense, prior to the adjustment for the capitalized amount, is $3.527 million for both the Test and Rate Years. Mahoney PFT, pp. 42 and 43.

The Authority opines that there is no basis to increase NUSCO capital funding expense by simply changing the capital/expense allocation applicable to the Rate Year. No evidence was presented to support the claim that a change in the payroll capitalization ratio had any correlation to CL&P's use of the shared capital investments.

The Authority concludes that the capitalization ratio should be the same for both the Test and Rate Years. Therefore, the Authority will maintain the NUSCO capital funding expense at the Test Year level of $2.701 million and disallows $402,000.

13. Storm Reserve

Catastrophic storms are those events in which CL&P incurs incremental expense in excess of $5 million. The storm reserve is currently funded through the distribution rate at the level of $3 million per year. CL&P recognizes that funding the reserve at the level necessary to address storms of the same magnitude as Storm Irene in 2011 and the October 2011 Nor'easter and Storm Sandy in 2012 would not be reasonable. The Company proposed an amount for the annual storm reserve based on storm activity during the 2010-2013 period, excluding those storms. After excluding these events, CL&P stated that the existing collection of $3 million per year to fund the reserve is insufficient because its calculation of what would have been needed to fund the storm reserve amounts to $9.035 million annually. PFT Mahoney, pp. 30-32.

CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs for storms that meet specific criteria. Pre-staging costs include: securing outside line and tree crews, food and hotel support to accommodate such crews, and travel time for crews. The Company proposed to increase the annual catastrophic storm reserve funding level from its current level of $3 million to $11 million, which is a $6 million increase for incremental costs and a $2 million increase for pre-staging costs. This increase will ensure that there are reasonably sufficient funds in the reserve to mitigate the expense of future catastrophic storms and for potential storm pre-staging costs. Id., pp. 31 and 32.

To balance the interests of the Company and customers, CL&P proposed that if the storm reserve accumulates a net balance of more than $50 million, it would pay customers carrying charges at the weighted average cost of capital on the amount of the over-funding during the period of time that the over-funding situation exists. Correspondingly, during the period of time that the balance in the storm reserve falls below a net negative of $(50) million, then customers would pay carrying charges to the Company on the under-recovery during the period of time that under-recovery exists. For example, assume that the storm reserve contained a net balance of $55 million for a three-month period and decreased to $45 million due to a catastrophic storm that occurred in month four. Then the Company must pay customers carrying charges on the $5 million over-funding that existed in the storm reserve during that three-month period where the net balance of the reserve exceeded the $50 million threshold. Additionally, the Company proposed to have the ability to elect to credit to customers a portion of the positive balance held in the storm reserve exceeding the $50 million threshold when it makes adjustments to any other rate component on January 1st or July 1st through the existing administrative rate adjustment process. Id., p. 32.

The OCC recommended that the storm reserve remain at the $3 million level. The OCC based its recommendation on the fact that the Company included a $93.805 million capital expenditure request in the filing for system resiliency. It is a glaring inconsistency to include both $93.8 million for system resiliency and an increase of $8 million for the storm reserve accrual. According to the OCC, the Company is either

ignoring the positive effects of the resiliency plan or assumes that the plan will be ineffective. Ratepayers should not be asked to pay for two contradictory expenses. The OCC also argued that three of the storms used by CL&P in its calculation of the reserve are also included in the Company filing for separate recovery. It is inappropriate and could be considered double dipping to use the costs being recovered elsewhere as the basis for increasing the reserve calculation. Finally, the Company requested $2 million for pre-staging costs and the OCC references Mr. Bowes testimony in Docket No. 12-06-09. Mr. Bowes stated that the Company would be allowed to seek recovery of pre-staging costs in future proceedings after they were incurred. The Decision in that docket stated that the costs would be subject to a "detailed review" including thorough documentation. As the Company does not have actual costs for review and recovery, its request in the Application is inappropriate, untimely and should be disallowed. OCC Brief, pp. 64-66.

Regarding the double counting of storms, the OCC stated that unusual storms that are allowed recovery by other means should be excluded from the reserve calculation. The OCC points out that the Company excluded the costs for Storm Irene, the October 2011 Noreaster and the 2012 Storm Sandy because they were unusual. However, the Company's Table KBB-JLM-7, used to calculate the estimated storm reserve of $9 million included the June 2011 and September 2012 storms that were approved for recovery in the Decision dated March 12, 2014 in Docket No. 13-03-23, Petition of The Connecticut Light and Power Company for Approval to Recover Its 2011-2012 Major Storm Costs (Storm Cost Recovery Decision). The table also included the 2013 storm costs deferred and included in the Company's request for recovery in the current filing. The OCC argued that this is inappropriate since the Company already has a means for recovery for the catastrophic storms, such as the Storm Cost Recovery Decision. In analyzing previous storm reserve activity, the OCC stated that the Company did not charge any costs to the storm reserve in 2008 and 2009. In 2010, costs of $14.783 million were charged to the reserve and as of September 2014, there were no charges to the 2014 reserve. If the deferred storm costs are removed from the calculation, the OCC calculated that the remaining amount charged to the reserve over 2008-2013 is $15 million. Amortized over six years, it equals $2.5 million annually and represents a reasonable level. Id.

The Company stated that the OCC is incorrect in its contention that system resiliency spending should limit the need to fund the storm reserve above current levels. CL&P's system resiliency initiatives are comprehensive system upgrade measures that will strengthen and modernize the system on a systematic basis over a period of time. The long-term impact of these upgrades will not be fully realized until there is critical mass in terms of the percent of the system completed. The existing PURA-approved five-year (2013-2017) System Resiliency Plan addresses 7% of CL&P circuits. The OCC claims the current accrual amount of $3 million "is considered generous because the effects of a system resiliency plan should actually reduce the reserve amount." However, it argued that "the Company has barely started implementing the $300 million resiliency plan." In the opinion of CL&P, the OCC cannot have it both ways. If the Authority grants CL&P's request to increase the storm reserve, it will have an opportunity in the 2017 rate case to re-evaluate the reserve funding level, specifically, to determine whether the proposed $9 million contribution level will continue to be

appropriate given actual experience in the intervening time period. CL&P Reply Brief, pp. 52-53.

The Authority will first address the non pre-staging portion of the reserve request, which the Company proposed to increase from $3 million annually to $9 million annually. There is no debate that the Company has seen significant storm activity in recent history, this is well documented in the Storm Cost Recovery Decision where the Company sought recovery of $414 million for costs associated with historic weather events. Since those events, the Company has embarked on a capital spending program aimed at strengthening its distribution system. This is well documented in the Resiliency Decision.

The OCC is correct that the Company has a means for recovery of catastrophic storm expense, which would be the request for the establishment of a regulatory asset to be recovered. There is also an expectation that the capital spending that the Company is performing should have a beneficial effect on storm expense items. It is also of note that the Company is planning to file for its next rate case in two and one-half years from the time of the conclusion of this docket. In an instance where the Company incurred storm costs as it had in 2011-2012, before its next rate case, the reserve as proposed would offer little relief to ratepayers. The shortened time frame between rate cases provides an opportunity for the Authority to gauge the effectiveness of the resiliency work that the Company is performing and will provide a better measure of what a storm reserve will be going forward. The Authority will maintain the Company's annual $3 million reserve and therefore, reduces the Company's request by $6 million. The Authority also denies the Company request for a storm reserve fund with carrying charges or credits.

14. Incremental Storm Costs Included in Base Rates

The Company currently recovers $9.6 million in rates annually to offset the cost of non-catastrophic storms. These are storms in which the Company's per-storm incremental expense is less than $5 million. Costs associated with this category of incremental expense include such items as overtime, intercompany expenses for labor, materials and supplies, travel expenses and outside services including services of other utilities, electrical and tree trimming contractors. The Company does not propose any increase to the current $9.6 million that is collected annually to offset the cost of non-catastrophic storms. The Company is using an historical average for Rate Year expense purposes similar to that used by the Authority in 2009 CL&P Rate Case Decision. As reflected in Table MJM-8 below, CL&P identified the incremental storm expense of $9.6 million by taking the incremental storm expense after capitalization and transferring it to the storm reserve for 2008-2013 of $57.9 million. The total net incremental cost was then reduced by removing the low and high years (2011 and 2010, respectively) to yield a net incremental storm expense. This net incremental storm expense amount was then averaged based on the remaining costs during the four years that were selected out of this six-year period, which produced an average annual amount of approximately $9.6 million. The Company reflected the adjustment for the $9.6 million in Schedule C-3.21 along with workpapers illustrating how it derived the average.

Table 54
O&M Expense for Non-Catastrophic Storms 2008-13
($000's)

Rate Year Calculation	Historical Amounts	
2008	$ 14,428	
2009	8,603	
2010	15,451	
2011	3,983	
2012	11,437	
2013	4,041	
Six Year Total	57,943	
Less: Low Year (2011)	(3,983)	
Less: High Year (2010)	(15,451)	
Adjusted Total	38,509	
4 Year Average	$ 9,627	(a)
(a) Round the rate year to	$ 9,600	

Workpaper C-3.21.

The OCC recommended that the Company's Test Year expense of $4.041 million be allowed in the Rate Year and that the increase of $5.559 million be rejected. The Company included a significant increase in major storm expense. The requested amount increases the expense for major storms despite the fact that the Company has included a large increase in expense for system resiliency. The OCC claimed that in ignoring the impact of the system resiliency plan, the Company is trying to have it both ways. For CL&P to justify the extensive costs of its resiliency system, it must acknowledge some positive impact on storm damage. OCC Brief, p. 68.

The Company stated that the OCC's proposal is inconsistent with the methodology of using a multi-year average, as the Authority in CL&P's last two rate cases, the 2009 CL&P Rate Case and Docket No. 07-07-01, Application of The Connecticut Light and Power Company to Amend Rate Schedules (2007 CL&P Rate Case). The OCC did not object to the use of this methodology in the 2009 CL&P Rate Case, and proposed using a multi-year average calculation in the 2007 CL&P Rate Case. Additionally, there are several instances in this case where the OCC proposed using multi-year averages to support its proposed reductions in this case; but the OCC avoids using a multi-year average here because in so doing, supports the current recovery level of $9.6 million. The OCC's sole justification in support of its substantial reduction to CL&P's current annual collection for non-catastrophic storms is its claim that the Company's proposal "ignores the increase requested in the system resiliency program." This assertion ignores the reality that the benefits of that system resiliency plan will take time to achieve. In 2017, when CL&P is expected to request the PURA to establish new distribution rates, the Company asserted that the Authority will have an opportunity to re-evaluate the non-catastrophic storm funding level to determine whether an adjustment is appropriate given actual experience in the intervening time period. CL&P Reply Brief, pp. 53 and 54.

The Authority finds that this item differs from the storm reserve in that the reserve is built into base rates and the expense is funded throughout the year through customer

rates. If the amount is less than the amount included in base rates in a particular year, the Company has collected rates for an expense that it did not incur. Conversely, if the amount is more than the amount included in base rates in a particular year, the Company has not collected rates for an expense that it did incur. Therefore, it is important to set the level of incremental storm expense at an appropriate level.

As mentioned, the Company calculated the level of incremental storm expense based on historical experience from 2008-2013, with adjustments that remove the high and low amounts in that time period, 2010 and 2011. The OCC's protest to this approach is that it does not take into consideration the amount of resiliency work that is being performed on the system, which the OCC claimed should reduce storm related costs. The variation of this item over the years and the Company's smoothing of the expense by removing high and low points from its request, result in the Authority find this to be an appropriate level for this expense at this time. Experience between now and the Company's next rate case will provide additional data points for the Authority and all parties to consider at that time. Again, this item differs from the reserve as this is an item built into base rates as opposed to the reserve. The Authority therefore allows an incremental storm expense of $9,600,000.

15. Pre-Staging Costs

CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs, for the purpose of securing resources in advance of catastrophic storms. Pre-staging costs include, for example, securing external line and tree crews, food and hotel support to accommodate such crews, and travel time for those crews. The Company asserted that it is necessary to recover eligible pre-staging costs because the EDCs must undertake necessary preparations to be able to comply with the Authority's storm performance standards and to restore power within the timelines stakeholders demand. CL&P noted that in 2012 and 2013, it incurred $609,000 and $1,622,000, respectively, in pre-staging costs for storms that were expected but ultimately did not occur. Mahoney PFT, pp. 31 and 32; Response to Interrogatory AC-92.

The Company also stated that pre-staging costs cannot be predicted in advance of a storm event. According to CL&P, each storm is different and they are always difficult to predict. Since resources must be pre-arranged that are located one to four days' travel time from Connecticut, financially significant issues must be made in advance of storm impact. Whether the storm materializes or not, CL&P still incurs these costs. Finally, the Company opined that there is currently no ratemaking mechanism by which it can recover pre-staging costs since they are not routinely incurred. Bowes PFT, pp. 45-48.

The OCC stated that the Company does not have actual detailed pre-staging costs available for review. Therefore, the $2 million per year expense should be disallowed as inappropriate and untimely. OCC Brief, p. 64.

The Authority strongly encouraged CL&P to devote greater efforts to pre-staging resources in anticipation of a major storm. In its Decision dated August 1, 2012 in

Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms (2011 Storms Decision), the Authority stated:

> In the future, CL&P should place higher priority on taking aggressive action in anticipation of such events, including pre-staging resources and making earlier attempts to acquire resources.
>
> The Authority finds that CL&P should establish a heightened state of readiness and be able to clearly document that such a state exists. In conjunction with this expectation, the Authority will order CL&P to report on actions it has taken to establish a heightened state of readiness in anticipation of a major storm including an assessment of its own lineworkers and lineworkers from sister companies and contractors. CL&P shall also state the mutual assistance organizations to which it belongs and the resources likely available from those organizations. The Authority requires that the primary emphasis of this report focus on those resources that are likely to be available during the first 48 hours of a major storm event to assist in efforts to ensure public safety. The Authority will also order the company to demonstrate its efforts to establish a heightened state of readiness.
>
> 2011 Storms Decision, p. 51.

In its investigation into the response to Storm Sandy in 2012 that was documented in the Decision dated August 21, 2013 in Docket No. 12-11-07, PURA Investigation into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy, the Authority noted a number of actions that CL&P took to pre-stage resources, and concluded that the Company prepared very effectively for Storm Sandy, especially through procuring and pre-positioning supplemental lineworkers prior to the storm. Decision, pp. 16-19 and 54. This investigation confirmed the valuable role that pre-staging brings to major storm response.

The Authority previously recognized the major benefits of pre-staging resources to storm restoration and public safety. The Authority also recognized that decisions on pre-staging must be made several days in advance of catastrophic storms, when the severity and timing of such storms may not be known; however, the PURA has encouraged the EDCs to make conservative decisions to ensure the state is adequately prepared for a catastrophic storm. The Authority finds that since it has strongly encouraged both EDCs to take actions that will require them to incur pre-staging costs, the PURA should provide surety that the costs are recoverable to lessen any financial disincentive to take those actions. The Authority concludes that the requested funding level of $2 million per year is reasonable given that costs were incurred in 2012 and 2013. As these are preparation costs for storms that never occur, the Authority will look for prudent decision-making in incurring these costs. Therefore, the Authority allows the Company to fund a reserve for pre-staging costs at the $2 million/year requested level. Unused amounts will not be accumulated for future years. At the end of each calendar year, unused pre-staging amounts should be transferred to the non pre-staging storm reserve. The Company shall separately account for storm reserve and pre-staging

storm reserve amounts. Detailed activity in these accounts will be subject to audit and review at the Company's next rate filing or any other period deemed necessary by the Authority.

16. Additional Storm Costs

The Company seeks recovery for storm costs that were not addressed in the Storm Cost Recovery Decision. These costs amount to $31.068 million and relate to the windstorm of January 31, 2013, the blizzard of February 8, 2013, and the remaining Hurricane Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision. Amounts for these individual events are identified in Exhibits MJM-4 through MJM-6 of the Application.

The OCC stated that in calculating the additional level of storm costs, CL&P did not follow the capitalization policy applied by the Authority in the Storm Cost Recovery Decision because the Company argued that the treatment in that Decision was specialized. The capitalization classification changed with the Storm Cost Recovery Decision and should be followed on a going forward basis. The Company submitted a calculation that replicated the capitalization for the 2013 storms and Storm Sandy deferral using the procedure used in the Storm Cost Recovery Decision. The result is an additional $804,164 of capitalized items for the reclassification of costs associated with the 2013 storms and $7,010 for the residual Storm Sandy amount. This would reduce the amount subject to amortization by $811,174. The OCC recommended that the $31.068 million deferral requested by the Company should be reduced by $811,174 to $30.257 million. This would reduce rate base $446,000, net of deferred income taxes and it reduces amortization expense $116,000. OCC Brief, pp. 49 and 50; Late Filed Exhibit No. 51.

The Company stated that it has not adjusted the 2013 storm costs to reflect the adjustments made in the Storm Cost Recovery Decision because the determinations in that Decision were based on the unique factual circumstances of Storm Irene, the October 2011 Nor'easter and Storm Sandy, which were addressed in the Storm Cost Recovery Decision. CL&P asserted that the Storm Cost Recovery Decision did not change the Company's standard accounting practices for typical storms, nor did it establish new accounting practices for general application. As such, the Company recorded its costs related to the 2013 storms consistent with its standard accounting practices and with the treatment approved by the Authority in the past for typical storms. CL&P Response to Interrogatory AC-148.

The Authority agrees that the events contemplated in the Storm Cost Recovery Decision were based on the unique factual circumstances of those events. The Authority also finds that the Storm Cost Recovery Decision did not establish new accounting practices for general application. Going forward, the Authority will review events on a case by case basis to determine the appropriate accounting treatment to be afforded any particular event. The Authority sets a threshold amount of $20 million per event as the amount where CL&P must provide evidence that the Company's standard accounting practices are appropriate. In this Decision, the Authority approves the Company's request to recover $31.068 million related to the windstorm of January 31,

2013, the blizzard of February 8, 2013, and remaining Storm Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision.

17. Troubleshooter Organization

a. The Prior Troubleshooter Organization

The Company has used troubleshooters for decades. The Company claimed that its prior troubleshooter organization (TSO) was not structured or sufficiently robust to cover the geographic area and time periods necessary to restore power to customers in the minimal time achievable for the types of trouble events that occur during off hours. The Company routinely compares its outage response performance with other utilities using a JD Power customer survey (Survey) to measure how customers view CL&P's performance in this area. The Survey indicated that the Company performed below the average of its peers in customer satisfaction for the restoration of power following non-storm-related outages. In 2013, CL&P reported its Customer Average Interruption Duration Index (CAIDI), the average time required to restore service, was 107.1 minutes compared to a better peer average of 102 minutes, and that its service was scored at 604 compared to a better peer average score of 655. CL&P Response to Interrogatory OCC-166. In addition, the Survey revealed that 89% of the surveyed utilities have a TSO devoted to outage restoration and trouble response. The Survey also indicated that 93% use one-person crews that pair up, as needed, to accomplish repair work. Tr. 8/27/14, p. 102; Bowes PFT, pp. 35 and 36.

Utilities that have good performance in responding to outages and trouble calls as measured by CAIDI and have positive customer experience as measured by the JD Power Score have a TSO that is directly connected with their system operation center (SOC). These utilities have troubleshooter crews that cover different geographic areas, but report through a centralized organization structure. The roving crews are able to cross town, district, and divisional boundaries to respond to outages and trouble calls. In addition, crews working during a shift are brought together if repair work during that shift requires additional support instead of calling in additional crews that work on a different shift to provide such support. Id.

The Company had two other major concerns with the prior TSO, the stability of the day time workforce and quality of life issues for line workers. The daily work center schedules were substantially affected by the number and frequency of instances in which line mechanics from the first shift were called out to perform emergency restoration work on the second and third shifts because there were an insufficient number of troubleshooters to respond to outages on these shifts. When this occurred, it reduced the availability and the ability of line mechanics to complete planned work and meet customer appointments during the first shift due to necessary rest time, which resulted in adjusted work schedules. The quality of life for a large number of mandatory on-call employees was affected due to the employees being unable to develop predictable family and non-work-related schedules and being forced to be on-call during the summer to ensure adequate coverage. Id., pp. 35 and 36.

CL&P's prior TSO had two classifications of line workers. The first classification were line mechanics that worked the day shift Monday through Friday and were

primarily responsible for routine construction projects, maintenance of distribution lines, new service installations and, occasionally, responded to outages and trouble calls as necessary. The second classification was troubleshooters who were primarily responsible for responding to outages and trouble calls. Id., p. 34. According to CL&P, all of the troubleshooters are line workers, but not all line workers are troubleshooters. Tr. 8/27/14, p. 106. Prior to the implementation of the new TSO program, there were 49 CL&P troubleshooters covering primarily the first and second shift, seven days a week in some area work centers. Typically, there was one troubleshooter per area work center on the first and second shifts and the third shift was covered by a weekly on-call rotation. Id.

b. The New TSO

The Company reorganized its TSO in spring 2014 and it was fully implemented by June 1, 2014, to improve service levels and decrease the duration of outages on the second and third shifts and on weekends. The new TSO became centralized and expanded its troubleshooter organization of 49 FTEs by adding 119 contract line workers, 10 contract foremen and 4 contract general foremen to provide expanded coverage 24 hours a day all year. Tr. 8/27/14, p. 105; Bowes PFT, pp. 34 and 35; CL&P Response to Interrogatory AC-129.

The regular first shift, Monday through Friday, are staffed with CL&P line workers and the second and third shifts and weekends are staffed with contract line workers. The expanded TSO will provide coverage to address both small-scope and large-scope emergent work, such as outages and trouble calls. Generally, the troubleshooters are geographically disbursed across the system, but can be aggregated in teams to work together if the actual restoration project requires additional support. Under the new centralized organization, troubleshooters will be organized into three geographic areas, with supervision in each area reporting directly to a troubleshooter management team consisting of CL&P managers. Additionally, the new troubleshooter organization is no longer bound by the boundaries of the Company's area work centers or divisions. The troubleshooter managers report to the Director of System Operations, who also oversees the Company's SOC. This alignment of the new troubleshooter organization with the SOC helps the Company pursue and manage a consistent response to outages and other trouble, providing a consistent platform and set of expectations across CL&P for developing customer restoration estimates. Bowes PFT, pp. 37 and 38.

The three geographic areas of the TSO do not necessarily correspond to the Company's three new divisional boundaries because the troubleshooters are deployed in a manner that: (1) assigns them to those portions of the electric system that historically, and in the future, are more likely to sustain outages and trouble calls and not routine construction or new service work; (2) incorporates travel distance and time concerns due to varied geography and development density across the CL&P service area; and (3) incorporates varied customer density patterns. Troubleshooters will perform other routine, day-to-day work when they are not responding to outages and trouble calls such as cut-out additions and replacements, installations of animal guards, lightning arrestor change-outs, pole shifts, transformer upgrades and, during nighttime hours, street lighting repairs and flood light additions. CL&P will utilize qualified line contractors who are members of the International Brotherhood of Electrical Workers

(IBEW) labor union from a Connecticut-based line contractor. CL&P will continue to work with its existing unions to attempt to implement an internal workforce for the troubleshooter organization. Id.

The Company expected that the new TSO structure will improve customer service by reducing the off-normal working hour CAIDI by 40 minutes, which will lower CL&P's overall CAIDI by up to 15 minutes. In addition, the new troubleshooter crews will work 24/7 as their normal working hours. Also, the stability of the daytime workforce will be improved because daily schedules can be maximized with a stable resource level to increase the overall efficiency of the workforce. Schedule adherence can be maximized and the area work centers will more effectively meet customer appointments and take on more construction and system resiliency projects. CL&P indicated that hiring crews that work 24/7 will reduce the number of callouts of additional personnel and thus can help improve response rates for those instances when a callout is necessary. Lastly, the Company stated that quality of life issues for employees is expected to improve by avoiding multiple forced on-calls for weekends during the summer months, and providing weekend coverage as part of regularly-scheduled work. Id., p. 39.

c. Costs

The Company projected that the cost of the new TSO to be $10.7 million and estimated that savings from the avoidance of cost for overtime work, associated rest periods, overtime meals and their meal time costs would save $5.7 million. CL&P Response to Interrogatory OCC-167. The Company is requesting that the Authority allow an adjustment to Rate Year O&M expense of $5.0 million to cover the annual net cost of the organizational change. The Company claimed cost is warranted by the direct and substantial improvement in service quality that will result from the implementation of an industry best practice. Moreover, this cost is conservatively quantified based on the cost of internal labor to fill the additional troubleshooter positions, although the Company will be using contract resources to fill the positions for the foreseeable future. Bowes PFT, p. 41. The quantification of net cost of this new initiative is conservatively based on internal labor rates.

The greater availability of the contractor resources on-system will add to the Company's resources in larger-scale, system-wide emergencies such as storm events. These critical resources will be located in Connecticut, available to the Company, and will already be familiar with the electrical distribution system and the state's geography. As a result, the expanded TSO contractor workforce will be a valuable asset in storm response. Bowes PFT, p. 40.

d. Position of the OCC

The OCC is concerned that the Company's estimate of new TSO costs of $10 million has not been offset by costs in the test year. Schultz PFT, p. 36. The $15 million for outside services and contract labor is excessive. The OCC determined that $4.552 million was spent for overhead line maintenance and it covered the labor for 49 contract workers, which equates to approximately $92,000 per contract worker. By hiring 84 more contract workers at $92,000 per year, the contract labor costs would

increase to $7.803 million. The OCC concluded that the $15 million costs for outside services and contract labor less the TSO $5 million savings in labor cost and less the $7.8 million for contract labor results in an excess estimate of TSO costs of $2.2 million and recommended that the Company's request be reduced by $2.2 million. The OCC stated that a cost benefit analysis should be performed to show that there is a benefit from the new TSO. The OCC questioned the type and level of work to be performed at night and claimed that the Company's description of work to be performed at night is not typically performed at night. Id., pp. 36 and 37.

e. Authority Conclusion on the TSO

The Authority reviewed the record and CL&P's rebuttal to the OCC's claim that the cost of the new TSO is overstated by $2.2 million. CL&P explained that the OCC incorrectly assumed that 49 troubleshooters under the former TSO were outside contractors. The 49 troubleshooters were employees of CL&P. Further, the labor cost is irrelevant with the $4.552 million spent for outside services and contractor labor that the OCC used to calculate an average contractor labor rate. WP C.310, p. 2 of 2. CL&P's estimate of contract labor in the new TSO was based on adding 90 contractors consisting of 80 line workers, 8 supervisors and 2 managers. CL&P Response to Interrogatory OCC-167. The OCC based its estimated contractor labor cost on an additional 84 contractors which understated the labor costs. Bowes Rebuttal PFT, p. 12.

The Authority accepts CL&P's explanation that associating 49 CL&P employees with the $4.55 million spent for contractor services is inaccurate. The Authority finds that the calculation of the average contactor labor cost by the OCC is not supported and rejects the OCC's claim that the new TSO cost would be $15 million. The Authority finds no justification to accept the OCC's recommended $2.2 million funding reduction for the new TSO.

Based on the reported lower restoration times experienced during the second and third shifts and for weekends at utilities using the new type TSO, the potential of increased availability of CL&P line workers having a more certain work schedule during the first shift to meet scheduled appointments and service calls, the elimination of geographic boundaries so work crews can respond to any type of outage, the opportunity to adjust the number of contract workers due to seasonal work and having additional contract work in the service territory at the start of normal and major storms. The Authority will allow CL&P's request to annually fund $5 million for the new TSO. At the time of its next annual CAIDI reliability filing in March 2015, the Company shall report the CAIDI for the second and third shifts and for weekends and the average number of contract workers staffing each work period to demonstrate the change that the new TSO had on reliability for these periods and the overall system and report the annual contractor costs of the new TSO.

In its next rate case, the Company will also be required to report the annual CAIDI and JD Power service scores for CL&P and its peer group and justify the effect that the new TSO had on these results.

18. Computer Expense

In Revised Late Filed Exhibit No. 3, the Company requested $11.187 million in computer expense for the Rate Year based on a Test Year amount of $17,250 with a pro forma adjustment reduction of $6,063 million to the Test Year amount to arrive at $11,187 million ($17,250 - $6,063 = $11,187). This is an allocated amount from NUSCO to the Company. Late Filed Exhibit 3, p. 2.

The Authority reviewed the Company's percentage changes and compared it to Schedule G-2-16 attachment to allocate NUSCO computer expense to CL&P. The Company based its request on various types of computer expenses that have various percentages of allocation to CL&P to arrive at Rate Year computer expenses of $11,187. In addition, the Authority reviewed the NUSCO allocation and accepts the Company's rate year amount of $11,187 million.

19. Facilities Maintenance

The Test Year expense for facilities maintenance was $5.990 million with a pro forma adjustment amount of ($606) for the proposed Rate Year amount of $5.384 million. Revised Late Filed Exhibit No. 3, p. 2.

The Authority reviewed the charges that comprise the facilities maintenance and finds them to be appropriate at this time. Therefore, the Authority will allow and accept the Rate Year facilities maintenance expense of amount of $5,384 million.

20. Customer Service Expense

The Company proposed $3.795 million for its Rate Year customer service expense. Late Filed Exhibit No. 3. In its Late Filed Exhibit 36, the NUSCO total amount was $1.611 million of which $1.057 million was allocated to CL&P from NUSCO. Late Filed Exhibit No. 36, p. 6. The Company subsequently reduced the Test Year amount of $3.839 million by $44 to arrive at the Rate Year amount of $3,795. ($3.839-$44)=$3795).

The Authority reviewed charges that comprise the customer service expense account and finds them to be appropriate at this time. Therefore, the Authority accepts the CL&P Rate Year amount of $3.795 million for customer service expense.

21. Conclusion on Expenses

As discussed in the preceding sections, the table below summarizes adjustments to the Company's proposed expenses:

Table 55

Summary of Expense Adjustments

Descriptions	Amounts ($)
Amortization Expense	34,000
Board of Directors' Fees	(437,000)
Depreciation Expense	(7,440,000)
Directors' & Officers' Liability Insurance	(350,000)
Employee Incentive Compensation	(5,190,000)
Gross Earnings Taxes	(139,000)
NUSCO Capital Funding	(402,000)
Other Employee Benefits	(2,250,000)
Payroll Expense	(4,870,000)
Payroll Taxes	(414,000)
401k	(158,000)
Property Taxes	(1,988,000)
Rent Expense	(1,709,000)
Storm Reserve Accrual	(6,000,000)
Total Expense Adjustments	**(31,313,000)**

D. TAXES

1. Gross Earnings Tax

Based on its current rates, CL&P reported Gross Earnings Tax (GET) expenses of $69.126 million for the Test Year and proposed $69.566 million for the Rate Year. Late Filed Exhibit No. 3, Schedule WPC-3.37, pp. 1 and 2. For the proposed additional revenue requirements, the Company proposed incremental GET expenses of $8.659 million for revenues from distribution operations; $1.792 million for system resiliency; and $5.186 million for regulatory storm costs. Late Filed Exhibit No. 3, Schedules A-1.0, p. 1; A-1.0 A, p. 1; and A-1.0 B, p. 1. Therefore, the total GET expense proposed for the Rate Year is $85.203 ($69.566 + $8.659 + $1.792 + $5.186) million.

As discussed in Section II.E. Gross Revenue Conversion Factor, the Authority calculated a GET Rate of 7.0606%. CL&P proposed total present base rate revenue of $983.676 million for the Rate Year. Late Filed Exhibit No. 3, Schedule WPC-3.37, p. 2. The total additional revenue requested for the Rate Year is approximately $221.098 million. Id., Schedule A-1.0. Thus, the total proposed revenue requirement subject to GET is $1,204.774 ($983.676 + $221.098) million, and the Authority determines that the GET expense on this amount is $85.065 ($1,204.774 x 7.0606%) million. As a result, the Authority reduces the GET expense proposed for the Rate Year by $139,000 ($85,203,000 - $85,065,000).

2. Interest Synchronization

The Authority adjusted the rate base amounts proposed by the Company and no change was made to the cost of long-term debt. Therefore, an interest synchronization adjustment is made to match the allowed rate base and with the income tax calculation. The rate base reduction adjustments reduces interest expense deductions for income for tax purposes and conversely increases income tax expenses. The tables in Section V. Rate Model, include adjustments to income taxes to reflect the impact of interest synchronization.

3. Municipal Property Taxes

CL&P reported property tax expense of $66.231 million for the Test Year and proposed $81.121 million for the Rate Year. Application, Schedules C.3.35, WPC-3.35A and WPC-3.35B. CL&P stated that property tax expense for the Rate Year is based on known assessed property values, updated for estimated depreciation, capital additions, retirements, and escalated mill rates. The property tax expense is amortized over the 12 months in a fiscal year beginning on July 1st. Mahoney PFT, p. 38. Furthermore, the Company indicated that its facility consolidation plan resulted in several reductions to the operating expenses for the Rate Year, including reductions to property tax expenses. Id. In its updated filing, CL&P increased its proposed property tax expense for the Rate Year to $81.435 million. Late Filed Exhibit No. 3, Schedule WPC-3.0, p. 1; WPC-3.35 A, p. 1. The revised request is to correct for a $75,000 calculation error in the Company's original filing and to reflect updates to estimated mill rates. Id. The Company total property tax expense proposed for the Rate Year equals the sum of 50% of the total actual property tax expense of $77,915,194, or $38,957,597, for the 2013 list year, plus 50% of the total estimated property tax expense of $84,382,289 or $42,191,145, for the 2014 list year. Id., Schedules WPC-3.35 A, p. 5 and WPC-3.35 B, p. 4. The total estimated property tax expense for the 2014 list year was determined by escalating the 2013 list year's personal and real estate property mill rates by 4%. Id. For tangible personal property, the Company reported a composite mill rate of 31.48 for the 2013 list year and 32.74 for the 2014 list year. Late Filed Exhibit No. 3, Schedules WPC-3.35 A, p. 5 and WPC-3.35 B, p. 4.

a. Escalation of Mill Rates

Concurrent with its previous rulings regarding mill rate escalations, the Authority concludes that the Company's proposal to escalate actual mill rates by 4% is not supported.[18] No evidence was provided in this proceeding that municipalities in the Company's service territories would, on average, increase their mill rates by 4%. The actual mill rate data available is for the 2013 list year. With the escalation removed, the Authority determines that the total estimated property tax expense for 2014 list year is $81,133,216 and for which 50% is $40,566,608 ($81,133,216 x 50%). As a result, the Authority disallows property tax expense of $1,624,537 ($42,191,145 - $40,566,608).

[18] See the 2009 CL&P Rate Case Decision, pp. 83 and 84; and the 2007 Rate Case Decision, pp. 74 and 75.

The Company stated that neither the OCC, the AG, nor any other participant opposed its proposal to escalate the 2013 list year mill rates by 4%, which equates to the $1,624,537 municipal property tax expense disallowed in the Proposed Final Decision. CL&P stated that its estimated mill rates escalation of 4% is conservative based on actual mill rate increases of 4.26% for list years 2010-2011; 7.14% for 2011-2012; and 4.41% for 2012-2013. However, the Company agreed to settle for a smaller mill rate escalation of 2% for the Rate Year and recommended that the Authority reduce the property tax expense reduction to $812,268.50 instead of the $1,624,537 disallowed in the Proposed Final Decision. CL&P Written Exceptions, pp. 45 and 46.

The Authority maintains its determination in the Proposed Final Decision that an arbitrary escalation of municipal property mill rates is improper as it ignores other variables that may impact actual property tax expenses.

b. Projected Plant Additions and its Depreciated Value

For the 2014 list year, CL&P reported total plant additions of $233.789 million and based on its proposed composite depreciation rate of 2.56%, it calculated a related net book value of approximately $227.804 million. Late Filed Exhibit No. 3, Schedule WPC-3.35B, p. 4. Using the 70% assessment factor, CL&P calculated total assessment value of approximately $159.463 million for the 2014 list year plant additions. Id.

The Authority takes issue with both the total plant addition and the related net book value amounts that the Company used to calculate the additional property tax requested. The Authority determines that the total plant addition for calendar year 2014, which the Company used as the proxy plant addition amount for the 2014 list year, is approximately $231.456 million. Schedule B-2.0; Tr. 09/12/14, p. 2398. CL&P stated that the difference of approximately $2.333 million is due to timing differences between the cutoffs for filing property tax and the Application. Id. Nevertheless, the Company agrees that the actual timing difference amount could go in either direction of the plant additions proposed for this proceeding. Id., p. 2399. For the 2014 list year, the personal property declaration period essentially runs from October 1, 2013 through September 30, 2014. Given the fact that only nine months in 2014 falls within the 2014 list year time frame, the Authority concludes that the 2014 list year plant addition timing difference would likely result in a declared amount less than the calendar year 2014 plant additions of $231.456 million. Therefore, the Authority recognizes the calendar year 2014 plant additions of $231.456 million as an appropriate proxy for property tax additions and disallows $2.333 million of plant additions from the calculation of property tax expense for the Rate Year.

Pursuant to Conn. Gen. Stat. §12-63(b)(6), the depreciated value of tangible personal property in their first year of declaration is 95% of acquisition costs. Thus, the Authority infers that the Company's depreciation composite rate of 2.56% is not applicable for the calculation of net book value for the proposed plant additions. Thus, the net book value for calculating the assessment value is 95% of the acquisition costs for the 2014 list year plant additions

c. Capitalized Expense Related Items

Based on discussions in Section II.C.2.i. Summary of Adjustments to Payroll Items, and Section II.C.3.e. 401(k) and K-Vantage, the Authority reduces plant-in-service by $8,834,351 for capitalized payroll related expenses and by $185,595 for capitalized 401K expense. Therefore, the Authority calculated a total plant addition amount for which additional property tax expense is applicable of $222.436 ($231.456 - $8.834- $0.186) million. Based on the foregoing, the Authority determines that the assessment value for the plant additions that should be included in the 2014 list year is $147.920 ($222.436 x 95% x 70%) million. Consequently, the Authority reduces the property tax expense associated with the proposed plant additions by $363,376 ($159.463 - $147.920) million x 0.03148).

In summary, the total reduction to the Company's proposed property tax expense is $1,987,913 ($1,624,537 + $363,376).

E. GROSS REVENUE CONVERSION FACTOR

The Company proposed a gross revenue conversion factor (GRCF) of 1.8252 for the Rate Year. Schedules A-3.0, A-3.0 (A) and A-3.0 (B). CL&P used a GET rate of 7.072% to calculate its proposed GRCF. This GET rate was determined by dividing the Test Year's GET expense of $69.126 million by the billed distribution revenue of approximately $977.414 million. Schedule WP C-3.37, p. 1.

The Authority finds that the proposed GET rate was overstated because CL&P did not incorporate unbilled revenues into the total base revenue used for the calculation. Based on CL&P's responses in this proceeding, unbilled revenues related to distribution, conservation and load management, and renewable operations are summarized below:

Table 56

Operations	Unbilled Revenues
Distribution	$1,514,144
Conservation and Load Management (C&LM)	137,787
Renewables	(30,268)
Total Unbilled for Distribution GET Expense	$1,621,663

Response to Interrogatory AC-70 Attachment 1, p. 2.

The total revenues proposed for the Rate Year encompass all revenues, billed and unbilled. Also, the proposed revenue deficiency represents the difference between the total Test Year revenues and the proposed Rate Year revenues at present rates. The Authority disagrees with CL&P's use of only billed revenue to calculate the proposed GET rate. The appropriate total base distribution revenue for calculating the GET rate is of $979.036 ($977.414 + 1.622) million. Therefore, the Authority calculated a GET rate of 7.0606% ($69.126 / $979.036). Consequently, the Authority determined that the appropriate GRCF for the Rate Year is 1.8250.

F. COST OF CAPITAL

1. Introduction

In determining the appropriate allowed cost of capital, Conn. Gen. Stat. §16-19e(a)(4) requires that:

> The level and structure of rates be sufficient, but not more than sufficient, to allow public service companies to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable.

To determine a rate of return (ROR) on rate base that is appropriate for CL&P's overall cost of capital, the Authority first identifies the components of the Company's capital structure. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed ROR.

The Company retained the services of a cost of capital expert, Mr. Robert Hevert, to present evidence, to provide a recommended return on equity (ROE), and to assess the reasonableness of the Company's capital structure and cost of debt. The Authority notes that the Company is proposing to use the Test Year equity ratio, instead of the forecasted capital structure supported by CL&P's witness, Mr. Robert Hevert. The capital structure is discussed in more detail below.

2. Capital Structure

a. Capital Structure

The Company proposed rates that are based on a capital structure consisting of 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt. Hevert PFT, p. 56. CL&P's long-term capital structure goal is to have an approximate 52% to 48% equity to debt ratio, and to have that capital structure used for ratemaking. CL&P Response to Interrogatory FI-52. Although CL&P plans to have an actual capital structure of approximately 52%/48% equity/debt in the Rate Year ending 2015, it has not made an adjustment to the Rate Year to reflect that expectation, and has instead reflected in this case, the equity ratio that existed at the end of the Test Year, December 31, 2013. The Company indicated that in its next rate case, it will present its actual capital structure. Mahoney PFT, p. 23. The Company's proposed capital structure and its corresponding component costs are depicted in the table below.

Table 57
Proposed 2015 Average Capitalization

Class of Capital	($000) Amount	% of Total	Cost	Weighted Cost
Long-Term Debt	2,770,150	47.61%	5.45%	2.60%
Preferred Stock	116,894	2.01%	4.80%	0.10%
Common Stock	2,931,000	50.38%	10.20%	5.14%
Total	5,818,044	100.00%		7.84%

Application, Schedule D-1.0.

As determined in the 2009 CL&P Rate Case, CL&P's currently allowed capital structure is 48.35% long-term debt, 2.45% preferred stock and 49.20% equity. CL&P Response to Interrogatory FI-53. As a measure of capital structure, Mr. Hevert calculated the average capital structures for each of his proxy companies which indicated an average common equity ratio range from 46.14% to 61% on an operating company basis. Hevert PFT, p. 58; Exhibit RBH-15, p. 2. Mr. Hevert's 15-member proxy group had an average capital structure consisting of 52.95% common equity, 0.25% preferred stock and 46.80% long-term debt. Id. Based on Mr. Hevert's capitalization analysis, CL&P's proposed and target capital structures are somewhat more leveraged than those in place at the utility operating companies held within the peer group. CL&P Response to Interrogatory FI-54. In Mr. Hevert's opinion, increasing the equity ratio to approximately 52% will serve to bring the Company in line with its peers, and would improve its ability to access the capital markets, at reasonable cost rates, under a variety of capital market conditions. Hevert PFT, pp. 59 and 60.

Mr. Hevert claimed that CL&P's capital structure has less equity than other electric utility operating companies rather than their consolidated parents, which he asserts is industry practice. Hevert PFT, p. 57. The OCC's cost of capital witness, Dr. Woolridge, contends that this assertion is incorrect because Mr. Hevert excluded short-term debt and also compared the capitalization ratios of the operating subsidiaries of the proxy group companies. Woolridge PFT, pp. 16 and 17. When evaluating financial risk, short-term debt must be included in a company's capitalization because it is a senior debt claim. As an example, Dr. Woolridge shows NU's, CL&P's parent company, common equity ratio of 49.64%, including short-term debt, which comprises 8.40% of the capitalization. Woolridge PFT, Exhibit JRW-5, Panel C. If short-term debt were to be excluded, then its average quarterly common equity ratio would only be 43.2%, a significant difference in common equity ratios. Also, comparing capitalization ratios of the proxy group's operating subsidiaries is incorrect because operating companies do not have common stock outstanding; therefore, these should not be used to estimate an equity cost rate. According to Dr. Woolridge, the proper comparison is to the actual proxy group capitalizations, including short-term debt. Id.

Dr. Woolridge provided the average quarterly capitalization ratios for all the holding companies in Mr. Hevert's proxy group which averaged 5.72% short-term debt, 45.86% long-term debt, 0.26% preferred stock, and 48.16% common equity. Woolridge PFT, p. 15; Woolridge Exhibit, JRW-5, p. 2. Given the proximity of the common equity ratio of 50.38% to those of the proxy group and NU, the OCC has accepted CL&P's

proposed capital structure. Woolridge PFT, p. 16. The OCC has adopted the Company's proposed capital structure and senior capital cost rates into its analysis. Woodridge PFT, p. 3.

In allowing a cost of capital, the Authority finds it reasonable to assume the additional equity of a 50.38% equity structure in the cost of capital calculation. The Authority determines that by slightly increasing the equity ratio from 49.20%, as determined in the Company's last rate case, to 50.38% would not dramatically increase the cost of capital, but will continue to support healthy debt ratings and expand CL&P's marketablility to attract the necessary capital. Ultimately, a strong capitalization should minimize the cost of capital through lower interest rate on financings as well as increase the availability of capital itself. While CL&P is striving to reach a 52% equity capitalization by the end of 2015, the Authority finds that the proposed 50.38% equity ratio in this rate proceeding is in line with its peers and other electric utilities with similar financing requirements and business risks. CL&P will continue to maintain its capital structure by coordinating in terms of timing and amount of common dividends paid to NU and the equity infusions that it receives from NU. As such, the Authority finds that a 50.38% equity proportion is more than fully adequate and should enable the Company greater access to the capital markets and financial flexibility.

b. Cost of Long-Term Debt

The Company's proposed average long-term embedded cost of debt for the 12 months ended December 31, 2015, was estimated at 5.45%, based on the 2013 Test Year equity ratio of 50.38%. Application, Schedule D, WP D-1.2, p. 3. The long-term debt consists of 19 series of first mortgage bonds and 9 series of pollution control revenue notes (PCRBs). CL&P Response to Interrogatory OCC-249. In order to balance the proposed capital structure, CL&P expects to issue $500 million of long-term debt in 2015. Tr. 9/10/14, pp. 1758 – 1761. The estimated embedded cost of debt also includes the unamortized cost associated with refinancing the 2005 Series A bonds and to fund the anticipated redemption of the 1996 Series A PCRBs. Unamortized costs for the PCRBs will be amortized over the term of the new first mortgage bonds. CL&P's Supplemental Response to Interrogatory OCC-249-SP01.

The Authority notes that based on CL&P's Order No. 1 compliance filing for the 12 months ended June 30, 2014, in Docket No. 76-03-07, Investigation to Consider Rate Adjustment Procedures and Mechanisms Appropriate to Charge or Reimburse the Consumer for Changes in the Cost of Fossil Fuel and/or Purchased Gas for Electric and Gas Public Service Companies, the Company lists an embedded cost of debt of 5.21%. CL&P has projected a higher embedded cost of debt of 5.45% for 2015. The OCC has accepted the proposed cost of debt into its recommendations. The Authority finds that 5.45% is a reasonable actual embedded cost of debt for CL&P as it reflects the current cost of any new planned debt issuances and refinancings.

c. Cost of Preferred Stock

The Company is expected to have $116,919 in preferred stock in its capital structure as of December 31, 2015, at a cost of 4.80%. Application, Schedule D-4.0. CL&P has 13 series of perpetual preferred stock that was issued between 1947 and

1968. Id. The Authority notes that rating agencies and investment banking firms treat preferred stock differently in that they will assign a credit to the mix of debt and equity. Based on discussions with the rating agencies, it is CL&P's understanding that equity credit for preferred stock can range from no credit to up to 50% credit. In the case of CL&P's preferred stock, Standard & Poor (S&P) considers 50% as equity and 50% as debt. CL&P Response to Interrogatory FI-57. This treatment of the Company's preferred stock has remained consistent in past rate proceedings, receiving 50% common equity credit. The 50% common equity credit assigned to CL&P's preferred stock reduces the amount of true common equity that the Company must maintain in order to achieve the same credit ratings objective. The Authority accepts the Company's proposed 4.80% costs as submitted in Schedule D-4.0.

3. Cost of Common Equity

In determining a return that is fair and reasonable while enabling the Company to operate properly and attract the necessary capital, the Authority judiciously reviewed all the testimony and evidence proffered by the witnesses in this proceeding and determines a change in CL&P's allowed return of 9.40% is warranted. The Authority finds it necessary to make various adjustments to the cost of equity data submitted in order to improve its analytical quality. These adjustments support a downward adjustment to the Company's currently allowed return. The Authority finds that the overall financial and economic indicators, business and financial risk and capital cost rates, in general, have declined since the time of CL&P's last rate proceeding. In addition, the merger of NU and NSTAR has enabled CL&P to have an even stronger financial position. The Company is obviously functioning in a relatively low interest rate environment, today, which has contributed to lower expected returns. The downward trend of approved ROEs nation-wide clearly signifies a lower cost of capital environment. Moreover, the Authority finds that the implementation of a full decoupling mechanism that helps mitigate the earnings pressure of the Company, further reduces the overall risk profile of the Company.

Therefore, in considering the arguments and analyses of the parties and intervenors, the Authority has set CL&P's ROE at 9.17**%**, and adopts such return in this proceeding. The Authority determines that such return is fair and reasonable, enabling the Company to operate properly and attract the necessary capital for capital investments. The cost of equity component, which is a measure of the investor's expected return, is discussed as follows:

a. Introduction

There are several methods commonly used to determine the appropriate cost of equity. The determination of the cost of equity in this proceeding was obtained using the discounted cash flow (DCF) method and the capital asset pricing model (CAPM) to a proxy group of companies. The DCF evaluates future cash inflows (dividends and capital gains) that investors expect to receive from a stock against the current market price investors pay for a stock. The discount rate that brings the present value of the cash flows exactly equal to the market price is the cost of equity. The Authority generally relies on the DCF analysis but also considers other methods. Accordingly, material was also presented using the risk premium CAPM by the Company's witness

and the OCC. The CAPM evaluates the cost of equity by determining first an appropriate risk free rate. To this rate it adds a beta (or the degree of co-movement of the security's rate of return with the market's rate of return) times the expected equity risk premium (the amount by which investors expect the future return on equities, in general, to exceed that on the riskless asset). The following is a summary of the positions of the parties on the subject of cost of equity:

b. Company ROE Proposal

The Company's cost of equity testimony was prepared by Mr. Hevert, a financial consultant on behalf of CL&P. Mr. Hevert advocated for an allowed ROE of 10.20% from a range of 10.20% to 10.70%. Hevert PFT, pp. 2 and 3. Mr. Hevert's testimony relied on DCF model (including the Constant Growth, Quarterly Growth, and Multi-stage forms), the CAPM (including both the traditional form of the CAPM and the Empirical CAPM), and the Bond Yield Plus Risk Premium approach to develop his cost of equity results by applying to a proxy group of electric utilities. Hevert PFT, p. 3. Although Mr. Hevert did not make an explicit adjustment to his recommended ROE of 10.20% for flotation costs, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Hevert PFT, pp. 51 and 52; Exhibit RBH-14. Reflected in his recommended ROE of 10.20%, Mr. Hevert calculated a 14-basis point adjustment to reasonably represent flotation costs for the Company. Id. In determining where the Company's ROE falls within his range of results, Mr. Hevert also took into consideration the Company's existing and proposed Earnings Sharing Mechanism, its proposed Decoupling Mechanism and the implications of certain State policy goals included in the Comprehensive Energy Strategy. Hevert PFT, p. 4.

As CL&P's stock is not publicly traded, Mr. Hevert's initial cost of equity calculations were primarily based on a proxy group of 15 publicly traded utility companies. Hevert PFT, pp. 6 – 11. However, Mr. Hevert subsequently revised the analyses for the proxy group presented in his direct testimony based on updated data through July 31, 2014. Hevert Rebuttal Testimony, dated August 22, 2014, p. 69 and Rebuttal Exhibit RBH-11. Using this updated data resulted in one company being eliminated to form a 14-member proxy group. To determine the composition of the proxy group, Mr. Hevert began with the universe of 47 companies from Value Line's Electric Utilities Industry. Mr. Hevert then applied the following screening criteria to determine his recommended proxy group: 1) consistently pay quarterly cash dividends; 2) covered by at least two utility industry equity analysts; 3) investment grade senior unsecured bond and/or corporate credit ratings from S&P; 4) regulated operating income over the three most recently reported fiscal years comprised of at least 60% of the respective totals for that company; 5) regulated electric operating income over the three most recently reported fiscal years represent at least 90% of total regulated operating income; and 6) not known to be party to a merger, or other significant transaction as of July 31, 2014.

The Authority notes that 24 of the companies were eliminated from Value Line's Universe of Electric Utilities based on Hevert's fifth criteria of a company having at least 90% of regulated electric operating income. Response to Interrogatory FI-88. The companies included in this proxy group with their ticker symbols were American Electric Power Company (AEP), Cleco Corporation (CNL), Duke Energy Corporation (DUK),

Empire District Electric Company (EDE), Great Plains Energy (GXP), Hawaiian Electric Industries (HE), IDACORP (IDA), NextEra Energy (NEE), Otter Tail Corporation (OTTR), Pinnacle West Capital Corporation (PNW), PNM Resources (POR), Southern Company (SO) and Westar Energy (WR). Prior to updating the data used for the proxy group, Mr. Hevert indicated that one of his proxy group companies, Pepco Holdings, announced the acquisition by Exelon on April 30, 2014, subsequent to the period used in the initial analyses. Hevert PFT, p. 11. Pepco Holdings was the company that was eliminated from Mr. Hevert's updated proxy group.

After selecting the 14-member proxy group, a cost of equity was calculated using a DCF method. Although Mr. Hevert recognizes the Authority places more weight on the Constant Growth DCF approach, he contests that there are a number of assumptions and constraints that may affect the reasonableness of its results. Therefore, Mr. Hevert included the Quarterly and Multi-Stage models, as well, to address those concerns. Hevert PFT, pp. 13 and 14. In theory, the standard DCF formula is based on the stock's current price reflecting the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the cost of equity as the discount rate that sets the current price equal to expected cash flows. The Constant Growth DCF model assumes: 1) a constant average annual growth rate for earnings and dividends; 2) a stable dividend payout ratio; 3) a constant price to earnings multiple; and 4) a discount rate greater than the expected growth rate. Hevert PFT, p. 14. In other words, assuming that the earnings and the dividends of a company grow at a constant rate, the DCF takes the standard form, whereas, the first term is the expected dividend yield and the second term is the expected long-term annual growth rate.

$$K = [D_0 \times (1 + g) / P] + g$$

where: K = Discount rate or Investor's required ROE

D_0 = Annualized dividend per share as of July 31, 2014

P = Current stock price (average 30, 90 and 180 day price)

g = Expected long-term annual growth rate (Zacks, First Call, Value Line, Sustainable Growth)

The first step in implementing the constant growth DCF model is to determine the expected dividend yield which is simply the annual dividend divided by a stock price. Hevert PFT, pp. 14 and 15. Mr. Hevert originally calculated the dividend yield based on the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods ended April 15, 2014. However, Mr. Hevert subsequently updated his analyses based on the data through July 31, 2014. Hevert Rebuttal Testimony, p. 69. Mr. Hevert adjusted the dividend yield to account for periodic growth in dividends by applying one-half of the long-term growth rate to the current dividend yield. While Mr. Hevert does not disagree with the Authority's use of Value Line as a sole source for projected dividends, he elected to use Bloomberg Professional Service as a source because it reflects the views of multiple analysts. Hevert PFT, p. 16. Mr. Hevert's original testimony calculated the average adjusted dividend yields using the 30-day, 90-day and 180-day average stock prices at 4.01%,

4.12% and 4.20%, respectively, for the period ending April 15, 2014. Hevert PFT, Exhibit RBH-1, pp. 1 – 3. As a result of using updated data through July 31, 2014, the average adjusted dividend yields using the 30-day, 90-day and 180-day average stock prices were reduced to 3.81%, 3.88% and 3.99%, respectively, for the 14-member proxy group. Hevert Rebuttal Exhibit RBH-1, pp. 1 – 3.

For the purpose of the DCF model, the next step is to develop a single growth rate component that reflects investors' growth rate expectations for the electric utilities. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Hevert PFT, p. 16. According to Mr. Hevert, the fundamental measure of growth is earnings because dividends are paid from earnings and book value can only increase through retained earnings or with the issuance of new equity. His findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Hevert PFT, pp. 17 and 18. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and Value Line.

Additionally, Mr. Hevert included the sustainable growth approach to estimate a company's expected growth. The sustainable growth model is based on the theory that a firm's growth is a function of its expected earnings and the extent to which those earnings are retained and reinvested in the company. Hevert PFT, p. 18. This is calculated by the formula, g = br + sv, whereas 'b' is the expected retention ratio, 'r' is the expected return on equity, 's' is the common equity to be issued annually as new common stock and 'v' is the equity accretion rate. The 'br' portion of the formula projects growth as a function of internally generated funds. The Company stated that the 'sv' portion of the equation reflects an element of growth as the product of the growth in shares outstanding, and that portion of the market-to-book ratio that exceeds unity. As such, Mr. Hevert represents the 'sv' term as: (M/B – 1) x Common Shares Outstanding, whereas, M/B is the market-to-book ratio. Hevert PFT, p. 19; Exhibit RBH-2. As historical experience suggests that future earnings do not necessarily increase as the retention ratio increases, Mr. Hevert does not believe it is an appropriate measure of expected growth. However, recognizing that the Authority has included sustainable growth as a measure of expected growth in the DCF approach in prior proceedings, Mr. Hevert produced two sets of DCF analyses, one including sustainable growth rates and another excluding those estimates. Hevert PFT, pp. 20 and 21. Using Value Line as the source for the data, Mr. Hevert calculated an average sustainable growth rate of 4.39% for his proxy group. Rebuttal Exhibit RHB-1, pp. 1 – 3. Combining the long-term earnings growth estimates with the sustainable growth, resulted in an average growth rate of 5.28% for the 14-member proxy group. Excluding the sustainable growth rate, resulted in an average earnings growth of 5.61% for the comparable companies. Hevert Rebuttal Exhibit RHB-1, pp. 4 – 6.

For the constant growth DCF, Mr. Hevert calculated the high and low DCF results by combining the maximum and minimum EPS growth rate estimate as reported by Value Line, Zacks, First Call and sustainable growth with each company's dividend yield. Based on updated data through July 31, 2014, the constant growth DCF results, including sustainable growth, resulted in a reduced range of 7.58% to 10.95% (compared to 7.57% to 11.16% using data as of April 15, 2014). Excluding the

sustainable growth, the constant growth DCF produced a range of 8.26% to 10.87% (compared to 8.24% to 11.08% as of April 15, 2014). Hevert Rebuttal Testimony, p. 70, Tables 9a and 9b; Hevert PFT, pp. 21 and 22, Tables 3a and 3b.

According to Mr. Hevert, the constant growth DCF model is limiting because it assumes dividends are paid annually, and, consequently, likely to understate the cost of equity. Hevert PFT, pp. 22 and 23. While the adjusted yield is meant to address that assumption, it does not reflect the quarterly receipt and reinvestment of dividends. For that reason, Mr. Hevert developed the quarterly growth DCF model. This model replaces the D component of the constant growth DCF model with the following equation: $D = d_1(1 + k)^{.75} + d_2(1 + k)^{.50} + d_3(1 + k)^{.25} + d_4(1+k)^0$, whereas, d_1, d_2, d_3, d_4 is the expected quarterly dividends over the coming year, and 'k' is the required ROE. To calculate the expected dividends over the coming year, Mr. Hevert obtained the last four paid quarterly dividends for each company, and multiplied them by one plus the growth rate. Again, using the closing stock prices over the 30, 90 and 180 trading days period ending July 31, 2014, the quarterly growth DCF results ranged from 7.71% to 11.20% (compared to 7.69% to 11.40%, as of April 15, 2014) including sustainable growth, and 8.41% to 11.12% (compared to 8.38% to 11.32%, as of April 15, 2014), excluding sustainable growth. Hevert Rebuttal Testimony, p. 70, Tables 9a and 9b; Rebuttal Exhibit RBH-3; Hevert PFT, p. 24, Exhibit RBH-3.

The Company also developed a multi-stage DCF model which is an extension of the constant growth form that enables the analyst to specify growth rates over three distinct stages. Hevert PFT, p. 24. In the first two stages, cash flows are defined as projected dividends. In the third stage, cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period (terminal price). In each of the three stages, the dividend is the product of the projected EPS and the expected dividend payout ratio. Mr. Hevert relied on the projected payout ratios as reported by Value Line and used a long-term growth rate of 5.70% which is based on the real GDP growth rate of 3.27% from 1929 through 2013, and an inflation rate of 2.36%. However, Mr. Hevert subsequently updated the long-term nominal growth rate to 5.74%. Mr. Hevert testified that the slight change was due to an increase in the expected inflation rate. Tr. 9/10/14, pp. 1787–1789. Mr. Hevert calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (discount rate) and the long-term expected growth rate. Hevert PFT, pp. 25 – 27. Using the Gordon model to calculate the terminal value, the multi-stage DCF analysis produced a range of results from 9.51% to 10.58% (compared to 9.46% to 10.75% in the original PFT). Hevert Rebuttal Exhibit RBH-4, pp. 1–20; Exhibit RBH-4, pp. 1-19. Of the three DCF approaches, Mr. Hevert stated that the multi-stage is better in that it provides the ability to take into account the fact that market conditions are changing, that companies may change their payout ratios over time and there may be some compression in the price-to-earnings ratio at the end of the day. Tr. 9/10/14, pp. 1776–1778.

In addition to the DCF models, Mr. Hevert employed the use of a traditional CAPM and an empirical CAPM (ECAPM), which are both risk premium-based models constructed as a forward looking estimate of market equilibrium that measures risk using the beta coefficient. The CAPM analysis estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors

for the non-diversifiable or systematic risk of the security. Hevert PFT, p. 29. According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Hevert PFT, p. 30. Systematic or non-diversifiable risk is measured by the beta coefficient. The basic CAPM is mathematically expressed as:

$$K = R_f + B(R_m - R_f)$$

where: K = required market ROE for a security

B = beta, or systematic risk, for that security

R_f = risk-free rate of return

R_m= required return on market portfolio

$(R_m - R_f)$ = market risk premium

Since electric utilities typically are long-duration investments, the 30-year Treasury yield is most suited for the purpose of calculating the cost of equity. Hevert PFT, pp. 30 and 31. Mr. Hevert used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term projected rate or consensus forecast of 4.03% as the risk-free rates. Hevert Rebuttal Exhibits RBH-5 and RBH-7. Mr. Hevert claimed that the current rate of 3.35% was the 30-day average as of July 31, 2014. Tr. 9/10/14, p. 1792.

After determining the risk-free rates, Mr. Hevert calculated three versions of the market risk premium. He relied on two forward-looking (ex-ante) estimates and included a third estimate that is a combination of the simple average of the ex-ante method, the Supply Side model, and the long-term historical average market risk premium. Hevert PFT, pp. 31 and 32. His first estimate required the use of Bloomberg as the data source for a DCF-derived market risk premium of 10.12%. Hevert Rebuttal Exhibit RBH-5. The 10.12% was performed by calculating for each of the S&P 500 companies for which Bloomberg provided consensus growth rates which resulted in a 13.47% required market return and then subtracted the 3.35% risk-free rate. The second market risk premium of 10.05% was derived by using the projected earnings growth rates as provided by Value Line which equated to a required return of 13.40% and again subtracting the 3.35% risk-free rate. Id. The third estimated market risk premium of 8.31% is a simple average of incorporating Ibbotson's long-term historical (ex-post) of 6.96% and Supply Side model of 6.12% together with the above ex-ante market risk premiums. Hevert Rebuttal Exhibit RBH-7. All of the expected or required market returns use analysts' EPS growth rate projections.

As for the betas, Mr. Hevert considered the beta coefficients reported by Bloomberg and Value Line for his 14-member proxy group. Hevert PFT, p. 32; Rebuttal Exhibit RBH-11. Updating the data for the 14-member proxy group, the average proxy group beta from Bloomberg was 0.783 and Value Line was 0.74. Hevert Rebuttal Exhibit RBH-6. While the betas are very similar, Mr. Hevert explained that Value Line calculates the beta coefficient over a five-year period and Bloomberg's is based on two years of data. Hevert PFT, p. 33. Based on the updated figures and the variations

discussed above, Mr. Hevert produces CAPM results in the range of 9.46% to 11.96%, a decrease from the prior range of 9.74% to 12.16%. Hevert Rebuttal Testimony, p. 72, Table 10.

Mr. Hevert also included the ECAPM analysis in estimating the cost of equity, which is another variation of the CAPM. Hevert PFT, pp. 33 and 34. Mr. Hevert believes the ECAPM addresses the tendency of the traditional CAPM to under-estimate ROEs for low beta stocks such as regulated utilities. The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium, and applies a weight of 75% to that result. His model then applies a 25% weight to the market risk premium. The results of the two calculations are summed, along with the risk-free rate and takes on the following form:

$$K_e = R_f + 0.75B(R_m - R_f) + 0.25(R_m - R_f)$$

As with the CAPM, Mr. Hevert used the market DCF-derived ex-ante market risk premium estimates, the two measures of the 30-year Treasury yield as the risk-free rates and two estimates of the beta coefficient. Updating the inputs as of July 31, 2014, Mr. Hevert's ECAPM results currently range from 10.01% to 12.51%, compared to 10.21% to 12.74% as of the data provided April 15, 2014. Hevert Rebuttal Testimony, p. 72, Table 10; Hevert PFT, p. 34, and Table 9.

Besides the traditional CAPM and ECAPM, Mr. Hevert also evaluated the cost of equity for CL&P utilizing the bond yield plus risk premium method (RPM). Hevert PFT, pp. 34 – 37. The risk premium approach is similar to the CAPM in that the equity risk premium measures the additional risk required by investors for investing in equities rather than less risky assets, such as a company's debt. Typically, the RPM uses a market-based estimate to serve as a proxy for the market's return. Mr. Hevert used an alternative approach by gathering data from 1980 through July 31, 2014, of the actual authorized returns for electric utilities to serve as the proxy for estimating the equity risk premium. Id.; Hevert Rebuttal Testimony, p. 72. He defined the risk premium as the difference between the authorized ROEs and the then-prevailing level of long-term 30-year Treasury yields which resulted in the long-term average equity risk premium of 4.44%. Rebuttal Exhibit RBH-8, p. 18. However, Mr. Hevert stated that simply applying the long-term average equity risk premium of 4.44% would significantly understate the cost of equity and produce results well below any reasonable estimate. Hevert PFT, p. 37; Tr. 9/10/14, pp. 1795 – 1798. Because the data covers a number of economic cycles, Mr. Hevert used a regression analysis approach to measure the equity risk premium relative to a proportional change in the 30-year Treasury yields. To account for that variability, the risk premium is expressed as:

$$RP = a + B(\ln(T_{30}))$$

The results of the regression analysis confirms the inverse relationship between the relatively low level of the current 30-year Treasury yields and the equity risk premium. Including data through July 31, 2014, the 4.44% equity risk premium was adjusted further to 6.79%, 6.26% and 5.41% to reflect the relatively low yields of the current, projected near term and projected long-term, respectively. Rebuttal Exhibit RBH-8, p. 1. Adding the adjusted equity risk premiums to the current and projected 30-

year Treasury yields, resulted in an implied RPM range between 10.14% and 10.86% based on updated data through July 31, 2014.

In summary, Mr. Hevert's updated results determining the cost of equity using the Constant Growth DCF, Quarterly Growth DCF, Multi-stage DCF, CAPM, ECAPM and RPM methodologies to support a recommended range of 10.20% to 10.70%, with the allowed ROE of 10.20%. Mr. Hevert subsequently updated the analyses for the proxy group based on updated data through July 31, 2014. Mr. Hevert's cost of equity calculations were primarily based on a final proxy group of only 14 publicly traded utility companies. The following charts provide a summary of Mr. Hevert's ROE calculations, using updated data through July 31, 2014.

Table 58
Summary of CL&P's ROE Results

DCF Results - Including Sustainable Growth:

Constant Growth DCF	Low	Mean	High
30-Day Average	7.58%	9.10%	10.78%
90-Day Average	7.64%	9.17%	10.85%
180-Day Average	7.75%	9.27%	10.95%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	7.71%	9.28%	11.02%
90-Day Average	7.78%	9.35%	11.09%
180-Day Average	7.89%	9.46%	11.20%
Multi-Stage DCF	**Low**	**Mean**	**High**
30-Day Average	9.51%	9.89%	10.37%
90-Day Average	9.58%	9.84%	10.45%
180-Day Average	9.70%	10.09%	10.58%

DCF Results - Excluding Sustainable Growth:

Constant Growth DCF	Low	Mean	High
30-Day Average	8.26%	9.43%	10.70%
90-Day Average	8.33%	9.50%	10.77%
180-Day Average	8.43%	9.61%	10.87%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.41%	9.63%	10.93%
90-Day Average	8.48%	9.70%	11.00%
180-Day Average	8.59%	9.81%	11.12%
Multi-Stage DCF	**Low**	**Mean**	**High**
30-Day Average	9.68%	9.98%	10.35%
90-Day Average	9.75%	10.06%	10.43%
180-Day Average	9.87%	10.18%	10.56%

CAPM Results:

CAPM	Bloomberg Derived MRP	Value Line Derived MRP	Average Supply Side Ex-Ante RP
Average Bloomberg Beta - 0.783			
Current 30-Year Treasury (3.35%)	11.28%	11.22%	9.86%
Near Term Projected 30-Year Treasury (4.03%)	11.96%	11.90%	10.54%
Average Value Line Beta - 0.74			
Current 30-Year Treasury (3.35%)	10.79%	10.74%	9.46%
Near Term Projected 30-Year Treasury (4.03%)	11.48%	11.43%	10.15%

ECAPM Results:

ECAPM	Bloomberg Derived MRP	Value Line Derived MRP	Average Supply Side Ex-Ante RP
Average Bloomberg Beta - 0.783			
Current 30-Year Treasury (3.35%)	11.82%	11.76%	10.31%
Near Term Projected 30-Year Treasury (4.03%)	12.51%	12.45%	10.99%
Average Value Line Beta - 0.74			
Current 30-Year Treasury (3.35%)	11.46%	11.41%	10.01%
Near Term Projected 30-Year Treasury (4.03%)	12.14%	12.09%	10.70%

Risk Premium Results:

Bond Yield Plus Risk Premium	30-Year Treasury Yield	Risk Premium	Return on Equity
Current 30-Year Treasury (3.35%)	3.35%	6.79%	10.14%
Near Term Projected 30-Year Treasury (4.03%)	4.03%	6.26%	10.30%
Long Term Projected 30-Year Treasury (5.45%)	5.45%	5.41%	10.86%

Hevert Rebuttal Testimony, pp. 69–73.

Although an explicit adjustment for flotation costs was not added to the recommended ROE of 10.20%, Mr. Hevert calculated a 14 basis point adjustment to reasonably represent flotation costs for the Company. In addition, Mr. Hevert also took into consideration the Company's existing and proposed Earnings Sharing Mechanism, its proposed Decoupling Mechanism, financial and business risks and the capital market environment in determining where the Company's ROE falls within his range of results. These considerations are discussed in more detail in II.F.3.f, Flotation Costs.

c. OCC's Position

Dr. Woolridge advocated a 8.90% ROE in this proceeding based on the capital structure proposed by CL&P which includes a common equity ratio of 50.38%. Woolridge PFT, p. 2. Using the proposed Test Year capital structure and senior capital cost rates, the OCC recommended an overall rate of return of 7.14%. Woolridge Exhibit, JRW-1. Dr. Woolridge employed the use of the DCF and CAPM approaches to a 32-member electric proxy group. Dr. Woolridge also applied these methods to CL&P's cost of capital witness' proxy group of companies. Id.

Dr. Woolridge established a proxy group which consists of 32 publicly-held electric utility companies. Woolridge PFT, p. 13. Dr. Woolridge's proxy group includes companies that meet the following criteria: 1) at least 50% of revenues are from regulated electric operations as reported by *AUS Utilities Report*; 2) listed as an electric utility by *Value Line Investment Survey* and listed as an electric utility or combination electric and gas utility in *AUS Utilities Report*; 3) an investment grade corporate credit

and bond rating; 4) has paid a cash dividend for the past three years, with no cuts or omissions; 5) not involved in an acquisition of another utility and not the target of an acquisition in the past six months; and 6) analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters and/or Zacks. The resulting proxy group is comprised of: ALLETE, Inc., Alliant Energy Corporation, Ameren Corporation, American Electric Power Co., Avista Corporation, Black Hills Corporation, Cleco Corporation, CMS Energy Corporation, Consolidated Edison, Inc., Dominion Resources, Inc., Duke Energy Corporation, Edison International, Empire District, El Paso Electric, Entergy Corporation, Great Plains Energy Incorporated, Hawaiian Electric Industries, Inc., IDACORP, Inc., MGE Energy, Inc., Nextera Energy, Northeast Utilities, Northwestern Corporation, PPL Corporation, Pinnacle West Capital Corp., PNM Resource, Inc., Portland General Electric Company, OGE Energy Corp., SCANA Corporation, Southern Company, Westar Energy, Inc. and Xcel Energy, Inc. Dr. Woolridge included CL&P's parent company, NU, into his proxy group simply because it met the selection criteria and given the size of the proxy group, including or excluding NU had no material impact on the results. OCC Response to Interrogatory FI-187. While Dr. Woolridge's proxy group provides a more comprehensive sample to estimate an equity cost rate for CL&P, he also included Mr. Hevert's proxy group in his analysis. Woolridge PFT, p. 14.

The average S&P bond ratings for the Woolridge and Hevert proxy groups are both BBB+, whereas, CL&P's bonds are rated A-. Therefore, based on bond ratings, CL&P's investment risk is below that of the two proxy groups. In assessing the riskiness of CL&P's parent company relative to the proxy groups, Dr. Woolridge compared the beta, financial strength, safety, earnings predictability and stock price stability as published by ***Value Line***. NU's risk metrics on all five measures are virtually identical to the average for both proxy groups. Therefore, Dr. Woolridge considers that both proxy groups represent a risk-comparable group for CL&P, but the Company's risk is on the low side of these groups as indicated by the bond ratings. Woolridge PFT, pp. 14 and 15.

In developing a fair rate of return for CL&P, Dr. Woolridge primarily relied on the DCF model to estimate the cost of equity and applied it to the both Mr. Hevert's proxy group and his 32-member proxy group. Woolridge PFT, pp. 24 – 29. Given the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities since returns are set through the ratemaking process, Dr. Woolridge finds that the DCF model provides the best measure of equity cost rates for public utilities. Woolridge PFT, p. 24. The economics of the public utility business indicate that the industry is in the steady-state or constant growth stage of a DCF. Woolridge PFT, p. 28. Using the constant growth version of the DCF method, Dr. Woolridge first calculated the dividend yield by taking the current annual dividend and the 30-day, 90-day and 180-day average stock prices as of July 17, 2014. Tr. 9/10/14, p. 1845; OCC Response to Interrogatory FI-182. The mean and median dividend yields ranged from 3.6% to 3.9% for Woolridge's proxy group and ranged from 3.7% to 4.1% for Hevert's proxy group. Given these ranges, Dr. Woolridge used a dividend yield of 3.8% and 3.9% for Woolridge's and Hevert's proxy group, respectively. Woolridge PFT, p. 29. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. Therefore, to reflect the growth over the coming period, Dr. Woolridge adjusted the dividend yields by one-half the expected dividend

growth resulting in an adjusted dividend yield of 3.9% for Woolridge's proxy group and 4.0% for Hevert's proxy group. Woolridge PFT, pp. 29 and 30; Exhibit JRW-10, p. 1.

According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Woolridge PFT, p. 32. Dr. Woolridge stated that the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Woolridge PFT, p. 34. However, in Dr. Woolridge's opinion, investors are well aware of the upward bias in analysts' EPS growth rate forecasts, and therefore, the DCF growth rate needs to be adjusted downward since the stock prices reflect this bias. Woolridge PFT, pp. 35 and 36. Dr. Woolridge testified that the upward bias is not nearly as severe for electric utilities as it is for companies in general. Tr. 9/10/14, pp. 1847 – 1849. Dr. Woolridge used a dividend yield that reflects the 180-day trading period of average stock prices which mitigates the impact because it reaches back to 2013 when utility stocks were underperforming the overall stock market, as opposed to outperforming. Tr. 9/10/14, pp. 1849 and 1850.

For the growth component of the DCF calculation, Dr. Woolridge used a combination of historic and projected growth rates for earnings per share (EPS), dividends per share (DPS), book value per share (BVPS) and prospective earnings retention rates and earned returns on common equity as provided by *Value Line*. Dr. Woolridge also utilized the average EPS growth rates of Wall Street analysts as provided by Yahoo, Reuters and Zacks. Woolridge PFT, p. 31. Dr. Woolridge employs 13 measures of growth, of which 6 measure historic growth, and 7 are *Value Line* or Wall Street analysts' projections of growth, giving primary weight to the projected EPS growth rate forecasts of analysts. OCC Response to Interrogatory FI-188. For Dr. Woolridge's and Hevert's proxy group, the average of *Value Line's* historical median growth rate measures in EPS, DPS and BVPS is 3.60% and 3.0%, respectively. Woolridge PFT, p. 36; Exhibit JRW-10, p. 3, Panels A and B. The median of *Value Line's* projected growth rates for EPS, DPS and BVPS averaged 4.5% for Dr. Woolridge's proxy group and 4.3% for Hevert's proxy group. Id; Exhibit JRW-10, p. 4. The average of *Value Line's* internal growth for the proxy groups as measured by projected retention rate and return on shareholders' equity are 4.0% and 3.6%, for Dr. Woolridge's and Hevert's proxy group, respectively. Id. The mean and median of the 3 Wall Street analysts' projected EPS growth rates for the proxy groups are 5.0% and 4.9% for Dr. Woolridge's proxy group and 5.4% and 4.8% for Hevert's proxy group, respectively. To derive the overall growth rate for the proxy groups, Dr. Woolridge gathered all the data he collected to establish a range of estimates. Giving greater weight to the projected growth rate figures, Dr. Woolridge used the midpoint of the median range for each, resulting in a DCF growth rate of 4.875% for Woolridge's proxy group and 5.0% for Hevert's proxy group. Woolridge PFT, pp. 38 and 39.

Combining all the components of the DCF model, Dr. Woolridge calculated equity costs rates of 8.80% and 9.0%, for Woolridge and Hevert's proxy group, respectively. The details underlying the DCF-derived cost for equity for each proxy group is shown below.

Table 59

	Dividend Yield	1 + 1/2 Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Woolridge Proxy Group	3.80%	1.02438	4.88%	8.80%
Hevert Proxy Group	3.90%	1.02500	5.00%	9.00%

Dr. Woolridge also performed a CAPM analysis using both proxy groups. To determine an equity cost rate using the CAPM, there are three inputs: 1) the risk-free rate of interest, 2) beta (systematic risk measure), and 3) the expected equity or market risk premium. The yield on long-term Treasury bonds is viewed as the risk-free rate of interest in the CAPM and is readily observable in the markets. The yield on the 30-year Treasury bond has been in the 3.0% to 4.0% range over the 2013 to 2014 time period. Woolridge PFT, p. 41; Exhibit JRW-11. According to Dr. Woolridge, these rates are currently in the 3.35% range. Given the recent range of yields and the higher recent interest rates over the past two years, Dr. Woolridge elected to use 4.0% as the risk-free rate in the CAPM analysis. By using the top end of the range, Dr. Woolridge is building into it, a higher return. Tr. 9/10/14, p. 1853.

Dr. Woolridge stated that beta, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historic betas due to their tendency to regress to 1.0 over time. Woolridge PFT, p. 41. A stock with below average price movement, such as that of a regulated utility, is less risky than the market and has a beta of less than 1.0. Woolridge PFT, p. 42. Dr. Woolridge also found there to be several online investment information services that provide estimates of stock betas and these services can report different betas for the same stock due to the time period over which the beta is measured. As provided in the Value Line Investment Survey, the median betas for the companies in Woolridge's and Hevert proxy groups are 0.75% for both. Id.; Exhibit JRW-11.

The most contentious part of the CAPM is to measure the expected equity or market risk premium. The equity risk premium is the expected return on the stock market (such as, the expected return on the S&P 500) minus the risk-free interest rate (yield on the 30-Year Treasury). While the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market. Woolridge PFT, p. 43. To determine an equity risk premium, the OCC reviewed the results of over 40 equity risk premium studies and surveys performed over the past decade. These included the summary equity risk premium results of: 1) the annual study of historic risk premiums as provided by Ibbotson Associates; 2) ex ante equity risk premium studies commissioned by the Social Security Administration (as well as other similar studies labeled "Puzzle Research"); 3) equity risk premium studies of CFOs, Financial Forecasters, and academics; and 4) Building Block approaches to the equity risk premium. The overall median equity risk premium of these studies is 4.28%. Woolridge PFT, pp. 43 – 46; JRW-11, p. 5. To assess the effect of the earlier studies on the equity risk premium, Dr. Woolridge separately composed the results of the studies that were published after January 2, 2010, and

determined a median for this subset is 4.90%. Woolridge PFT, p. 47; Exhibit JRW-11, p. 6. According to Dr. Woolridge, much of the data indicated that the market risk premium is in the 4.0% to 6.0% range and the midpoint of 5% is used as the market risk premium for the OCC's CAPM analysis. Dr. Woolridge testified that he gives more credibility to the New York Fed's survey of numerous Wall Street firms that are actively involved in financial decision-making on a daily basis. Tr. 9/10/14, pp. 1854 – 1857. Based upon analysis and the inputs discussed above, Dr. Woolridge's CAPM resulted in a cost of equity of 7.80% for both proxy groups.

Table 60

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Woolridge Proxy Group	4.00%	0.75	5.00%	7.80%
Hevert Proxy Group	4.00%	0.75	5.00%	7.80%

In summary, Dr. Woolridge calculated equity cost rates of 8.80% DCF for Woolridge proxy group, 9.00% DCF for Hevert proxy group, and 7.80% CAPM for both proxy groups. Given these results, the OCC concludes that the appropriate equity cost rate for the proxy groups is in the 7.80% to 9.00% range. However, since Dr. Woolridge primarily relies on the DCF model, the OCC used the midpoint of the upper end of the range, concluding that 8.90% is the recommended equity cost rate for CL&P. Woolridge PFT, p. 49. Dr. Woolridge discussed several reasons why an 8.90% ROE is appropriate and fair for CL&P in this case: 1) CL&P is slightly less risky than the proxy groups as measured by its S&P bond rating of A-; 2) the electric utility industry is one of the lowest risk industries in the U.S. as measured by beta; 3) capital costs for utilities, as indicated by long-term bond yields and interest rates, are still at historically low levels; 4) while the markets have recovered significantly over the past five years, the growth in the economy is tepid and unemployment is still at 6.1%; 5) utilities have been the best performing sector of the market this past year; and 6) CL&P is a distribution-only electric utility that does not have the risks associated with the generation component of integrated utilities. While Dr. Woolridge did not consider the impact of the Company's proposed decoupling mechanism nor the earnings sharing mechanism on the OCC recommended ROE, he concurred that the mechanisms are reflected in the lower risk of Company. Tr. 9/10/14, pp. 1869 – 1871. Furthermore, Dr. Woolridge provided the authorized ROEs in 18 rate cases in 2013 and 2014 involving distribution-only electric utilities. There are no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%. Woolridge PFT, pp. 51 and 52.

Dr. Woolridge critiqued the most significant areas of disagreement in measuring CL&P's cost of capital which are: 1) the DCF equity cost rate estimates; 2) the market or equity risk premium in the CAPM and RP approaches; and 3) whether an equity cost rate adjustment is needed to account for flotation costs. In the DCF approach, the OCC finds there to be three major areas of contention with CL&P's DCF estimates, and in particular, Mr. Hevert's (a) decision to ignore 1/3 of his low-end DCF results, (b)

excessive reliance on the long-term EPS growth rates of Wall Street analysts and *Value Line* in developing a DCF growth rate, and (c) employment of an unrealistic projected GDP growth rate in his multi-stage DCF model. Woolridge PFT, p. 53. With respect to the asymmetric elimination of low-end DCF results, Dr. Woolridge stated that Mr. Hevert biases his DCF study and reports a higher equity cost rate than the data indicate. Dr. Woolridge continues that it appears that Mr. Hevert simply ignored the mean low DCF results for his constant and quarterly-growth DCF model application. In comparison, Dr. Woolridge stated that he used the median as a measure of central tendency so as to not give outlier results too much weight while not ignoring the impact of low and/or high results in determining an estimate for DCF. Woolridge PFT, p. 55.

Another area of concern for Dr. Woolridge with Mr. Hevert's DCF is the excessive reliance on the projected EPS growth rate forecasts of investment analysts as compiled by Zacks, First Call and *Value Line* in estimating an equity cost rate. Mr. Hevert's DCF growth rate in all three models employ the overly optimistic and upwardly-biased EPS growth rate estimates of Wall Street analysts. The OCC considered it to be a well-known fact that analysts' EPS forecasts are consistently too high. Woolridge PFT, p. 56 and Appendix B. In comparison, Dr. Woolridge reviews 13 different measures of growth to develop a DCF growth rate, including prospective dividend growth, internal growth, as well as projected earnings growth. Id.

Dr. Woolridge also highlights two critical errors in Mr. Hevert's multi-stage DCF approach which grossly inflates the projection of GDP as a growth rate. Woolridge PFT, p. 59. Dr. Woolridge claims that Mr. Hevert has not provided any theoretical or empirical support that long-term GDP growth is a reasonable proxy for the expected growth rate of the companies in his proxy group. Dr. Woolridge illustrated the historic measures of growth for earnings and dividends for both his and Hevert's proxy group which suggest growth that is 200 basis points below Mr. Hevert's 5.70% GDP growth rate. More importantly, Dr. Woolridge demonstrates that the projected GDP growth rate of 5.70% is not reflective of economic growth in the U.S., and is well in excess of projections of GDP growth. As such, Dr. Woolridge provided evidence that shows nominal GDP as well as its components, real GDP and inflation, have declined significantly in recent decades. Id; Exhibit JRW-14. With respect to GDP forecasts, there are several forecasts available from economists and government agencies of annual GDP growth that show a long-term growth range of 4.5% to 4.8%. Woolridge PFT, p. 61.

The OCC deems there to be two primary errors in Mr. Hevert's CAPM analysis which is the use of the ECAPM and the market premiums. Dr. Woolridge considers the ECAPM as nothing more than an ad hoc version of the CAPM and there is no empirical validation for the use of the weighting factors to boost the equity risk premium measure. Woolridge PFT, pp. 63 and 64. The major area of contention with respect to the CAPM and RP approaches is the measurement and magnitude of the market or equity risk premium. Dr. Woolridge demonstrates how Mr. Hevert's CAPM includes an expected return on the stock market that is not reflective of current market fundamentals, expected earnings, and GDP growth. Mr. Hevert's use of expected EPS growth rates from Wall Street analysts of 11.8% and 10.31% to produce estimated market returns of 13.91% from Bloomberg and 12.31% from Value Line, respectively, are not consistent

with historic or projected economic and earnings growth in the U.S. Woolridge PFT, pp. 65 and 66.

The national growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960 has averaged 6.50%, which demonstrates that Mr. Hevert's long-term growth rate projections are vastly overstated. OCC Brief, p. 25. Also, as discussed above, projected long-term GDP growth rate forecasts are in the 4.5% to 4.8% range. Woolridge PFT, p. 67. Moreover, the risk premium in Mr. Hevert's RP approach, which is based on the difference between authorized ROEs for electric utility companies and Treasury yields, is overstated because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Woolridge PFT, p. 72. In comparison, Dr. Woolridge uses a market risk premium which uses alternative approaches to estimating a market premium, and employs the results of over 30 studies and surveys of the market risk premium. Dr. Woolridge stated that his market risk premium is consistent with the market risk premiums: 1) discovered in recent academic studies by leading finance scholars; 2) employed by leading investment banks and management consulting firms; and 3) that result from surveys of companies, analysts, financial forecasters and corporate CFOs.

Mr. Hevert supported his DCF, CAPM and RP results with claims that the current market environment, flotation costs, and other factors suggest a higher equity cost rate is justified. Dr. Woolridge demonstrates that these factors should not be considered in setting the appropriate equity cost rate for CL&P.

d. Intervenors' Positions

i. Wal-Mart Stores

Pre-filed testimony of Steve W. Chriss, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart) was submitted with a recommendation concerning the ROE. Mr. Chriss demonstrates that the Company's proposed ROE of 10.2% is higher than ROEs approved by the Authority since CL&P's last rate proceeding and higher than those approved by other utility regulatory commissions. Chriss PFT, p. 17. As Mr. Chriss points out, there is a declining trend in authorized ROEs, particularly for distribution-only utilities. According to data from Regulatory Research Associates,[19] the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Chriss PFT, p, 18. The reported ROEs authorized by commissions were also recognized in Mr. Hevert's rebuttal testimony. Hevert Rebuttal Exhibit, RBH-20. However, the average reported ROE for distribution-only utilities was 9.57%, which is 63 basis points lower than CL&P's proposed ROE. Chriss PFT, p. 18. Mr. Chriss also revealed that in 16 recent utility rate cases in which Mr. Hevert provided expert testimony, the approved ROE decided in each case was lower than Mr. Hevert's recommended ROE in all cases. Chriss Late Filed Exhibit No. 35. In fact, each of the

[19] Regulatory Research Associates is part of SNL Financial, a financial news and reporting company.

16 recent cases in which Mr. Hevert provided expert testimony, all of the final approved ROEs were below Mr. Hevert's recommended ROE ranges. Id.

Mr. Chriss recommended that the Authority continue its practice of using recent Decisions to establish benchmark parameters and to indicate in which direction the allowed ROE should trend. Chriss PFT, p. 19. In addition, Mr. Chriss suggests that if the Authority approves a decoupling mechanism and earnings sharing mechanism for CL&P, it should consider the extent to which the implementation of these mechanisms reduces the business risk and be reflected in the Company's approved ROE. Chriss PFT, p. 4.

ii. AG's Position

The AG stated that the Authority should reject CL&P's proposed ROE of 10.2% since it is not consistent with recent PURA Decisions or analysis and is based on flawed and unreliable cost of capital analyses. AG Brief, p. 3. The AG generally supported the OCC's cost of capital testimony and its recommended ROE of 8.9%. However, the AG argued that the Authority should impose additional reductions to CL&P's authorized ROE to reflect the reduced business and operations risk from the revenue and sales decoupling mechanism. Id.

The AG contended that the Company's ROE is far out of line with recent Authority Decisions and would be the highest authorized return for any major regulated public service company in Connecticut. In the last 18 months, the Authority has not authorized a ROE over 9.2% and cites to the recently awarded returns of Connecticut Natural Gas Corporation, The United Illuminating Company and Aquarion Water Company of Connecticut. AG Brief, pp. 4 and 5. The AG also argued that CL&P's testimony in support of its proposed ROE of 10.2% contains errors that have distorted the Company's DCF, RP and CAPM analyses and unreasonably inflated its proposed ROE as demonstrated by the testimony and exhibits of the OCC's witness. As a result, the Company's recommended ROE is substantially higher than other similarly situated utility companies and substantially higher than the levels that the PURA recently approved for Connecticut's other public service companies. Id.

e. Authority Analysis – Cost of Equity

The Authority assessed the testimonies and recommendations of Mr. Hevert and Dr. Woolridge and is confident that the best solution to CL&P's cost of equity capital requirements still exists within the framework of the DCF model while considering the results of the CAPM. To test the results of the Company and the OCC witnesses, the Authority conducted its own cost of equity analysis of regulated utilities in an effort to take into account the differing approaches to estimating the cost of equity. The Authority's cost of equity analysis is based on the consensus positions and evidence gathered in Docket No. 09-10-06, Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (2009 Generic ROE Proceeding) in order to maintain consistency among rate proceedings. The Authority also takes notice that the testimony, arguments, calculations and methodologies by the OCC's consultant, have been uniform in the last several rate proceedings and have proved to be unfailing.

i. Analysis of the DCF Proposals

Since CL&P's stock is not publicly traded, a proxy group of companies comparable to CL&P must be developed in order to estimate the cost of equity. With regard to the choice of a proxy group, the Authority considered the Company and the OCC witnesses' proxy groups. The OCC chose to use the same 14-member proxy group derived by CL&P, as well as Dr. Woolridge's selection of a 32-member proxy group and performed analyses for both groups. Both the Company and the OCC used similar criteria in the selection of their proxy groups, such as those followed by Value Line, paid consistent quarterly dividends, covered by at least two utility industry equity analysts, an investment grade corporate credit and bond rating, and not involved in a merger, acquisition or other significant transaction. The Authority finds these to be reasonable factors to consider in the selection of the proxy companies.

The Authority takes issue with the percentage of regulated business criteria and it is the major difference between the Company and the OCC in that selection criteria. For example, the OCC recommended that proxy group companies have at least 50% of revenues from regulated electric business as reported by AUS Utility Reports. Alternatively, the Company cited that the basis for selecting its proxy electric companies was that it should represent at least 60% of total regulated operating income and 90% or greater of income from regulated electric operating income as conveyed in each companies' respective SEC 10-k filings and reported by SNL Financial. The difference of regulated operating revenues versus income and the source used to derive the data is not much of a concern as is the disproportion in the percentage of regulated business considered. The Company's selection criteria of having at least 90% of its regulated business from electric utility operations resulted in the elimination of 25 companies from Value Line's universe of 47 electric utility companies. This factor alone caused the greatest disparity between the Company and the OCC proxy group of companies. The Authority finds the Company's elimination of companies with less than 90% regulated income to be too restricting, while the OCC's criteria of at least 50% regulated revenues, too broad.

With respect to the proxy group selection criteria, the Authority reviewed prior rate proceeding decisions and closely followed the discussions by the parties in the 2009 Generic ROE Proceeding. According to the consensus, the Authority finds that the percentage of regulated business criteria to be 70% of regulated electric revenues as followed by *AUS Utility Reports*. The Authority finds the 70% valuation for an electric utility as appropriate and allows the PURA to create a pure play electric proxy group. Although it is not as restricting as the Company's 90% criteria, the Authority finds the 70% threshold still results in a large, robust proxy group. Including this modification to this selection criteria, the Authority's approved electric peer group (Authority Peer Group) represents the following selection criteria: 1) followed by Value Line; 2) has consistently paid dividends; 3) covered by at least two utility industry equity analysts; 4) has investment grade corporate credit and bond ratings; 5) not involved in a merger or takeover activity; and 6) 70% or more of revenues should be from regulated electric operations. Thus, the proxy group employed by the Authority to determine the cost of equity for CL&P lead to an Authority Peer Group of 25 comparable companies which includes: (ALLETE, Alliant Energy Corporation, Ameren Corporation, American Electric

Power, Consolidated Edison, Duke Energy, Edison International, Empire District, El Paso Electric, Entergy Corporation, Great Plains Energy, Hawaiian Electric, IDACORP, NextEra Energy, Northeast Utilities, NorthWestern Corporation, PG&E Corporation, Pinnacle West Capital Corporation, PNM Resources, Portland General Electric, OGE Energy, Southern Company, TECO Energy, Westar Energy, Xcel Energy). The table below provides a comparison of the proxy companies proposed by the Company, the OCC and also indicated those that passed the Authority's criteria.

Table 61

Hevert: Company Proxy Group	Woolridge: OCC Proxy Group	Authority Peer Group
	ALLETE, Inc.	ALLETE, Inc.
	Alliant Energy Corporation	Alliant Energy Corporation
	Ameren Corporation	Ameren Corporation
American Electric Power Co.	American Electric Power Co.	American Electric Power Co.
	Avista Corporation	
	Black Hills Corporation	
Cleco Corporation	Cleco Corporation	
	CMS Energy Corporation	
	Consolidated Edison, Inc.	Consolidated Edison, Inc.
	Dominion Resources, Inc.	
Duke Energy Corporation	Duke Energy Corporation	Duke Energy Corporation
	Edison International	Edison International
Empire District	Empire District	Empire District
	El Paso Electric	El Paso Electric
	Entergy Corporation	Entergy Corporation
Great Plains Energy Inc.	Great Plains Energy Inc.	Great Plains Energy Inc.
Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.	Hawaiian Electric Industries, Inc.
IDACORP, Inc.	IDACORP, Inc.	IDACORP, Inc.
	MGE Energy, Inc.	
Nextera Energy	Nextera Energy	Nextera Energy
	Northeast Utilities	Northeast Utilities
	NorthWestern Corporation	NorthWestern Corporation
	PPL Corporation	
	PG&E Corporation	PG&E Corporation
Pinnacle West Capital Corp.	Pinnacle West Capital Corp.	Pinnacle West Capital Corp.
PNM Resources, Inc.	PNM Resources, Inc.	PNM Resources, Inc.
Portland General Electric Co.	Portland General Electric Co.	Portland General Electric Co.
	OGE Energy Corp.	OGE Energy
Otter Tail Corporation		
	SCANA Corporation	
Southern Company	Southern Company	Southern Company
Westar Energy, Inc.	Westar Energy, Inc.	Westar Energy, Inc.
	Xcel Energy Inc.	Xcel Energy Inc.

In reviewing the DCF approaches, the Authority finds it necessary to address several differences between the Company and the OCC witnesses' applications of the model. Both the CL&P and the OCC witnesses incorporated the standard version of the DCF model to their proxy groups where the current dividend payment and stock price are directly observable. Although Mr. Hevert provided additional versions for estimating the DCF, such as the Quarterly and Multi-stage forms, the Authority finds the constant growth DCF model to be applicable due to the regulated stability and nature of public utilities, as well as the fact that returns on investment are effectively set through the

ratemaking process. The basic fundamentals of a regulated utility, such as CL&P, indicated that the industry is in a mature or steady-state stage of the three-stage DCF.

The DCF valuation approach for companies in this industry is the constant growth DCF. The constant growth DCF model is widely-accepted in the utility industry and is the most common method to calculate the ROE in regulatory proceedings. Consistent with past practice and industry standards, the Authority's preferred method is the constant growth form of the DCF that assumes dividends grow at a constant rate which simplifies to $K = D_1/P_0 + g$. Although the DCF seems straightforward, its components can vary widely depending on the type of growth measured and the time period selected. The Authority also considers the extent to which economic anomalies may affect the DCF analyses and prudently selects the individual components based on the current conditions within the constraints of the model and closely following the consensus of the 2009 Generic ROE Proceeding. The Authority is cognizant of the current market conditions and their relevant impact on growth rate recommendations, and reserves the right to use its judgment to form a reasonable estimate for the expected growth rate portion of the DCF model. As with each rate proceeding, a major point of contention is the computation of the growth component in the DCF, which is discussed further below.

After selecting the Authority Peer Group, the first step in the DCF is to calculate the average dividend yield. Both the Company and the OCC compute the dividend yield in a similar manner by using the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods and then adjusts the dividend yields by applying one-half of the long-term growth rate to the current dividend yield. Mr. Hevert's updated computation for the period ending July 31, 2014, resulted in adjusted dividend yields of 3.81%, 3.88% and 3.99%. Using both Mr. Hevert's proxy group and the OCC's 32-member proxy group, Dr. Woolridge employed the same approach for an adjusted dividend yield, but used the average stock prices as of July 17, 2014, to arrive at an adjusted dividend yield of 4.0% for Mr. Hevert's proxy group and 3.9% for OCC's proxy group.

Although the Company and the OCC employed comparable approaches to forecast the dividend yield in this proceeding, there is usually great deliberation over how much growth is to be applied (full year or half year) to forecast the dividend portion. To be consistent with prior proceedings, the Authority will incorporate *Value Line's* estimate of dividends to be paid over the next 12 months from *Value Line: Summary & Index*, column (f) as the D_1 input to the DCF model. This is based in part on evidence in the 2009 Generic ROE Proceeding and the fact that it is simply easier to utilize a number reported in *Value Line* than debate how much growth to be applied to inflate the current dividend. This debate can be lengthy in proceedings and the impact is *de minimis*. In fact, Mr. Hevert did not disagree with the Authority's use of *Value Line* as a sole source for projected dividends. Even though Mr. Hevert elected to use Bloomberg Professional Service as a source because it reflects the views of multiple analysts, he noted that the difference in results between the two sources is not significant. The Authority's analysis used *Value Line: Summary & Index* dated August 29, 2014, to obtain estimates of dividends to be paid over the next 12 months (D_1).

Regarding the time period that the data is collected, the Authority finds a 30-day average stock price long enough to capture changes in stock price movements and relatively simple to obtain from public sources online. Both the Company and the OCC used the average closing stock prices over three various time periods (30, 90 and 180 trading days) as its low, mean and high range for the dividend yield. The Authority incorporates a timeframe of 30 business days, or approximately 6 weeks, as reasonable for estimating the stock price portion for the dividend yield component of the DCF model. The Authority's time period covered six weeks ended August 29, 2014. Based on the Authority's Peer Group, resultant forecasted dividend yields used in the Authority's DCF model range from a minimum of 2.54% to a maximum of 5.17%. The mean (average) is 3.87%, while the median is virtually identical at 3.95%.

Next step is the calculation of long-term growth rates which is the most complex and debated issue of all the DCF components. There was agreement from the Company and the OCC that professional stock analysts' five-year forecasts for EPS growth and *Value Line's* projections for EPS should be included in the estimation of the overall growth component to apply in the DCF model. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and *Value Line* which reports the lowest, average and highest projected growth rates. Dr. Woolridge elected to use *Value Line's* projected growth rate estimates and the EPS growth rate forecasts as provided by Yahoo, Zacks and Reuters. The Authority finds little debate with regards to the incorporation of which professional analysts' EPS estimates to include and integrates EPS growth projections from *Value Line*, Yahoo Finance/I/B/E/S and Zacks.[20] The Authority chose not to include Thompson Reuters as a source of EPS forecasts since it would be redundant to Yahoo Finance which lists Thompson Reuters as the source of its summary EPS forecasts. For the Authority Peer Group, examination of the EPS growth rate data reveals a range of 1.0% minimum to a maximum of 11.0%, while the mean-average of the three estimates taken together was 4.94% and their median was 4.79%.

One area of contention between the Company and the OCC is over the inclusion of *Value Line's* projections for DPS and BVPS. Mr. Hevert chose only to focus on earnings growth in his analysis because earnings are the fundamental measure of growth, whereas, earnings growth enables both dividend and book value growth. Conversely, Dr. Woolridge included *Value Line's* projected growth rate estimates for DPS and BVPS as well as, the historic growth rates for EPS, DPS and BVPS. There is general agreement that the DCF concept presumes that earnings, book value, market price and dividends all grow at the same rate. The Authority finds that under the DCF theory and financial literature in general, all earnings will eventually accrue to investors through dividends and eventual sale of the stock. Even so, the cash stream an investor receives is a dividend and not the company's earnings. In reality, the investor only shares in those company earnings to the degree and timing the company wants the investor to participate in the company's performance (i.e., the dividend). A similar

[20] Value Line projected EPS, DPS and BVPS growth rates were obtained from the August 22, 2014 East edition; the August 1, 2014 West edition, and the June 20, 2014 Central edition. The 5-year EPS growth rates for Yahoo Finance (www.finance.yahoo.com) and Zacks (www.zacks.com) were obtained from their Internet domains on September 5, 2014 and September 8, 2014, respectively.

argument can be made for the inclusion of the BVPS growth rate into the DCF model since BVPS represents the underlying investment which generates earnings and therefore, dividends. Lastly, from a more practical view point, the Authority finds that it is unlikely that an investor would examine the *Value Line* sheet for a company and look only for the EPS projections while those forecasts for DPS and BVPS are also there. Based upon its review, the Authority finds DPS and BVPS to be relevant growth rates and incorporates *Value Line's* projections for DPS and BVPS in its analysis. For the Authority Peer Group, examination of the forecasted DPS and BVPS growth rate data reveals a range of 1.0% minimum to a maximum of 12.0%, while the mean-average of both estimates taken together was 4.44% and their median was 4.0%. Evidence shows the DPS and BVPS projections are slightly lower than those projections for EPS growth rates.

Another disparity between the Company and the OCC was the inclusion of *Value Line's* historic growth rates for EPS, DPS and BVPS in the estimation of the growth rate to be used in the DCF model. The OCC suggests that historic rates should be considered to provide a baseline of growth since investors have access to historic information, which provides the basis for investors' investment decisions. However, it appears Dr. Woolridge did not include the historic growth rate figures (3.6% and 3.0%) when establishing the appropriate growth rate range of 4.75% to 5.0%. The OCC explained that the projected rates are given more weight compared with the historic rates. While investors may not prefer or rely on historical growth estimates, the Authority does not believe investors completely ignore past history. However, the Authority finds that the *Value Line* historic growth rates for EPS, DPS and BVPS should not be a separate input included in a composite growth rate for the DCF model in this proceeding. Although historic growth estimates are excluded from the expected growth component of the DCF model, this does not suggest these historic growth figures have no place in the DCF analysis as they indicate the reasonableness of analyst forecasts. Therefore, the Authority considered the *Value Line's* 5-year and 10-year historical growth rate estimates for EPS, DPS and BVPS only as a base line measurement means for evaluation of the forecasts.

In addition to the growth rates discussed above, the Company and the OCC have included a sustainable or retention growth rate (retention rate = br + sv) as a measure of expected growth in the DCF analyses. According to financial theory, the sustainable growth formula (g = ROE x retention rate) is the best measure to estimate long-term growth rate expectations and the growth rate component of the DCF. As in past practices, the Authority focuses on the 'br' portion (internal growth) that is known as the earnings retention rate times the projected ROE. The primary debate with the sustainable growth rate is regarding the 'sv' portion (external growth) of the retention growth formula. There is agreement that *Value Line's* projections of BVPS take into account external growth. Likewise, the 'sv' portion is only applicable when a company is in the process of issuing stock to achieve external growth.

The Authority realizes that it is difficult to determine 'sv' as one needs to know when a utility will undertake a stock offering and even more difficult to determine the market-to-book ratio of that stock offering at the time of its issuance. Under this circumstance, the 'sv' portion should be widely disseminated to the investment public and should be known and measurable. This is unlikely to happen as companies do not

normally publicly report their plans to issue equity well in advance of the issue. It is clear that the greater portion of the sustainable growth rate does come from the 'br' portion. Examining the Company's assumption for estimating the 'sv', Mr. Hevert used the projected market-to-book ratio and the growth rate in common shares outstanding for the 's' portion while the 'v' portion was computed as 1 minus the projected market-to-book. In this case, the Company used *Value Line* projections for the increase in number of shares outstanding for each member of the proxy group. In other words, an assumption is being made that all the proxy group companies will be issuing shares and at an increase in value or at a price greater than book value.

The Authority finds this to be an unlikely assumption. Consequently, the Authority includes the sustainable growth formula, but places no weight on the 'sv' portion of the equation. The Authority's 'br' computation is obtained from the final projection's column (years 17-19) from *Value Line* company sheets. For the Authority Peer Group, examining the computed sustainable growth rate data shows that it ranges from a minimum of 2.47% to a maximum of 5.90%, with a mean-average of 3.90% and median of 3.72%.

To fully develop an understanding of what the composite or overall long-term growth will be for a company, various growth rates including dividend, earnings and book value growth must be taken into consideration. It is apparent that growth rates vary widely depending on the type of growth measured and the time period selected. The Authority was vigilant in analyzing different subsets of time periods within each type of growth rate because averaging different years or months of data can produce widely different results due to short-term fluctuation and oscillations in security prices. Also, the Authority finds sustainable growth is a significant and primary driver of long-run earnings growth. In its analyses, the Authority incorporated measures of growth for EPS, DPS, BVPS, as well as, sustainable growth rates. Prior to the close of the record in this proceeding, the Authority applied the latest editions and most recent measures of data found in the record or publicly available online in its analyses.[21] Use of the most recent issue of the Mergent Bond Record, Value Line editions, EPS estimates and updated stock prices revealed a decrease in interest rates, stock prices and growth rates since the Company and the OCC submitted their analyses.

In applying the DCF model, the Authority reviewed the annual constant growth form and incorporated a screening mechanism, based upon the rationale that the cost of equity should be greater than the cost of debt due to equity's greater risk. The Authority used the data in the record employing different measures of growth, including *Value Line's* 5-year projected growth rates for EPS, DPS and BVPS, as well as growth rates computed using the sustainable earnings/retention growth formula. The Wall Street analysts' forecasts of EPS obtained from Yahoo Finance and Zacks were also

[21] Value Line projected EPS, DPS and BVPS growth rates were obtained from the August 22, 2014 East edition; the August 1, 2014 West edition; and the June 20, 2014 Central edition. The 5-year EPS growth rates for Yahoo Finance (www.finance.yahoo.com) and Zacks (www.zacks.com) were obtained from their Internet domains on September 5, 2014 and September 8, 2014, respectively. The stock prices were derived from the historical prices from Yahoo Finance for a 30-day trading period ending August 29, 2014. The cost of debt recent issue was the August 2014 Mergent Bond Record.

incorporated into the DCF analysis. Overall, the Authority computed several scenarios using different estimates of growth. No one growth estimate was favored in place of another.

In the case of the electric industry, the Authority implements more stringent screening criteria as there is a large universe of publicly traded electric utilities. In addition to the initial proxy group screening criteria discussed above, the Authority set an acceptance criterion relative to the individual DCF results. With the changing market conditions, the Authority finds the screening mechanism for implausibly high and low DCF results to be beneficial. Regarding the low side threshold, the Authority finds as reasonable, the concept that equity is more risky than debt. Traditionally, the Authority's method has been to add 100 basis points to the average Mergent Public Utility Bond yield as its low end to screen individual DCF estimates. The cost of debt benchmark consists of the most current effective cost of long-term debt rate for each Authority Peer Group company using the latest Mergent Bond Guide as the source for the corporate bond yield averages. With the continuous decline in interest rates combined with the decrease in stock prices and growth rates, the Authority observed the individual DCF estimates also have fallen.

The latest Mergent Bond Record, August 2014 edition indicates that over the time period this rate proceeding commenced, the average Aa Public Utility Bond yield ranged from 4.23% to 4.07%. Applying the concept that equity is more risky than debt, the Authority finds it reasonable to increase the minimum basis point threshold above the cost of debt from 100 basis points to 375 basis points. Raising the minimum threshold to 375 basis points had the effect of eliminating 10 companies that had DCF estimates ranging from 6.49% to 8.22%. Those companies excluded were: American Electric, Consolidated Edison, Duke Energy, Edison International, El Paso Electric, Empire District, Entergy, IDACORP, PG&E Corporation and Pinnacle West.

Regarding the high side threshold, the Authority did not find it necessary to change the maximum benchmark set at 750 basis points and there were no companies eliminated. In this case, a definitive high end screen was not necessary given the DCF indicated results are low and below 10%. After establishing the minimum and maximum thresholds for the Authority Peer Group, the DCF estimate shows that it ranges from 8.02% to 10.69% with a mean-average of 9.03% and a median of 8.79%. The Authority finds the average of 9.03**%** to be a reasonable estimate of the indicated DCF cost of capital methodology. The Authority also finds this result is very conservative given the elevated threshold for screening the lower DCF estimates. Furthermore, the Authority highlights the fact that the Company's own constant growth DCF analysis using the 30-day average stock price, including its version of sustainable growth, produced DCF results of 7.58%, 9.10% and 10.78% for the low, mean-average and high, respectively.

ii. Analysis of the Capital Asset Pricing Models

The Authority evaluated the CAPM approaches employed by the Company and the OCC witnesses. There are several debates surrounding the application of the CAPM methodology, such as the actual use of other non-traditional forms of the CAPM and the equity risk premium estimates. The major controversy contiguous to the CAPM is always the calculation of the equity or market risk premiums. The Authority applied

the traditional CAPM to its proxy group using the standard formula of $K = R_f + B (R_m – R_f)$. The Authority applied an equity risk premium based on data of equity risk premiums in the record.

Reviewing the evidence regarding the selection of the risk-free rate of interest (R_f), does not show much controversy. The Company used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term consensus forecast of 4.03%. The OCC also recommended the recent 30-year Treasury bond yield of 4.0% to be conservative based on its observation that the 30-year Treasury bond yields have ranged between 3.0% to 4.0% over the 2013 to 2014 time period. The Authority reviewed recent trends in 30-year Treasury bond yields and finds that these have bounced up and down since 2013; however, since the beginning of 2014 interest rates have slowly decreased again. In fact, on the last day of hearings, before the record closed, the 30-year Treasury bond yield was 3.22%.[22] To be conservative, the Authority finds it reasonable to use the average of the Company (3.69%= [3.35%+4.03%]/2) and the OCC proposals of 3.845% (i.e., [3.69%+4%]/2) as an acceptable proxy for the return on long-term risk-free rate of interest, and incorporates this into its CAPM analysis.

The measure of beta represents the volatility of a proxy group of companies to the aggregate market. The OCC recommended use of *Value Line* adjusted betas, while Mr. Hevert considered the beta coefficients reported by both *Value Line* and Bloomberg. The Authority is aware that there are several online sources that provide estimates of stock betas and these services can report different betas for the same stock due to the time period over which the beta is measured. The Authority has relied on *Value Line* adjusted betas in the past, and therefore, incorporates *Value Line* betas into its analysis. The average beta of the Authority Peer Group is 0.75.

The primary concern with the CAPM is the estimation of the expected equity or market risk premium ($R_m – R_f$). The Company used three market risk premium measures of 10.21% (an ex-ante DCF-derived market risk premium from Bloomberg), 10.05% (an ex-ante market risk premium utilizing data from *Value Line*) and 8.31% (a simple average of the ex-ante Ibbotson model, Supply Side model, and ex-post or long-term historical average). With respect to Mr. Hevert's ex-ante measures using data provided by Bloomberg and *Value Line*, the Authority reviewed the Company's approach of using a DCF analysis on companies in the S&P 500 and back into a market risk premium and finds it to be an interesting approach to take. On the surface, the approach seemed reasonable but the Authority took issue with the execution of the method, especially with the expected EPS growth rates from Wall Street analysts used as inputs.

The Authority concurs with the OCC that these growth rates of 11.8% from Bloomberg and 10.31% from Value Line are inflated and not consistent with either historic or projected economic and earnings growth in the U.S. Of course, estimating the inputs to the DCF approach to generate an estimated return on the market requires

[22] The Company agreed to take administrative notice of recent and historical US Treasury Rates from www.treasury.gov in its Response to Interrogatory FI-67.

using analyst estimates of growth. Although it is difficult to evaluate the level of optimism in Wall Street analysts projected growth rates, it is a factor that needs to be considered in the evaluation of cost of capital especially when expected growth rates are involved. Regarding the Company's third approach to estimating a market risk premium, the Authority finds this to be a simple blending of the ex-ante and ex-post approaches that temper the impact of any one result of a particular method. The Authority included all three of the Company's market risk premium measures in its overall computation of a reasonable estimate for the equity risk premium, but gave these measures only one-third weight.

Regarding the OCC's equity risk premium, the Authority finds Dr. Woolridge's approach to be the most comprehensive in that it incorporates over 40 equity risk premium studies and surveys performed over the past decade. The OCC's recommended average market risk premium of 5.0% also incorporates the Ibbotson historical approach, as well as, both the arithmetic mean and the geometric mean approach. The OCC's approach is the most inclusive and has been included as an approach in numerous previous Decisions. Therefore, the OCC's proposed 5% is included in the Authority's methodology and is also given one-third weight in estimating the overall equity risk premium.

The Authority's review of equity risk premium determines that an investor should not expect a return much different than that produced by companies in the economy. In reviewing the methodologies presented, the Authority is drawn to the Ibbotson Supply Side Model. The Ibbotson Supply Side Model suggests that equity returns consist of inflation, the growth in real EPS, and income returns. The Authority notes that both the Company and the OCC presented the supply side within their estimate of the equity risk premium. One difference between the supply side model and the historical model calculations of Ibbotson is that the supply side excludes the growth in the price earnings ratio. Both calculations use the arithmetic mean and the difference is modest. For example, over the time period 1926-2013, the historical approach yields an equity risk premium of 6.20% while the supply side approach yields 6.12%. The Authority finds that the Ibbotson supply side approach is responsive to problems and biases contained in the historical data and is the best approach. Thus, the Authority incorporates the Supply Side equity risk premium of 6.12% and will apply to it a one-third weight in developing its equity risk premium.

In addition to the traditional CAPM, the Company proposed another variation known as the ECAPM which is basically a size or leverage adjustment of beta that increases the expected returns for low beta stocks and decreases returns for high beta stocks. As discussed previously, both the OCC and the Company used the Value Line betas which have been adjusted to address the empirical issues with the CAPM. The Authority has reviewed Mr. Hevert's ECAPM and finds that the only difference between the CAPM and ECAPM is the use of the weights or Alpha factor which is an arbitrary figure and has not been validated in referred journals. The Authority finds that the Alpha factor incorporates another level of conjecture that is unnecessary given that the simple CAPM formula is widely accepted in the cost of equity literature. Furthermore, the Authority has previously rejected the use of the ECAPM in numerous rate

proceedings.[23] As a result, the Authority rejects the notion of adding more layers of speculation or another variation to the CAPM, therefore, the Authority discards the ECAPM estimates from its analyses.

As with past practice, the Authority implemented a traditional CAPM cost of equity using the standard formula. First, the Authority incorporates the 6.12% from the Ibbotson Supply Side approach, the OCC's survey recommendation of 5% and the combination of the Company's 10.21%, 10.05% and 8.31%, to estimate the equity risk premium. These values are weighted equally for an Authority estimate of 6.88% representing the ($R_m - R_f$) calculation. Applying the Authority's assumptions using the simple CAPM formula (3.845% R_f + 0.75 B [6.88% $R_m - R_f$]), resulted in CAPM equity cost rate of 9.03**%** for the Authority Peer Group.

iii. Analysis of the Risk Premium Model

The Authority also reviewed the risk premium method employed by the Company. Mr. Hevert's risk premium method shows that the proxy for the utilities' cost of equity were the returns authorized by state commissions for the years from 1980 through 2014 and the respective Treasury yields for those periods. The resulting risk premium is applied to three different projected Treasury yields. The Authority notes that the OCC did not perform a utility risk premium and this method was not used in the cost of equity estimation process. The Authority concurs with the OCC that using the allowed authorized returns as a proxy for the return on the stock market reflected utility commission behavior. Jurisdictionally-allowed returns should not be relied upon as a proxy from a cost of capital approach, this should be market based and reflect investor behavior. The Authority finds that to allow utility state commissions' authorized ROEs to serve as a proxy for the stock return portion of a risk premium approach is to allow a non-market based estimate to serve as a proxy for the market's return. Cost of capital methods need to be market based. Therefore, the Authority rejects the Company's proposed risk premium method in total.

f. Flotation Costs

According to the Company, an adjustment to the ROE to include flotation costs is appropriate to not only reflect current or future financing costs, but also to compensate investors for costs incurred for all past issuances comprising the total equity portion of the Company's capitalization and are part of capital costs. Flotation costs are the costs associated with the sale of new issues of common stock and are part of capital costs. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance. Since flotation costs are incurred over time, the majority of flotation costs are incurred prior to the Test Year, but remain part of the cost structure during the Test Year and beyond. Mr. Hevert stated that recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such cost recovery may deny the Company the opportunity to earn its required

[23] *See* Decision dated August 14, 2013 in Docket No. 13-01-09, p. 137; and 2009 CL&P Rate Case Decision, p. 109.

rate of return in the future, thereby diminishing its ability to attract adequate capital on reasonable terms. Hevert PFT, pp. 49–52.

To calculate a flotation adjustment, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Mr. Hevert gathered the two most recent open market common stock issuances for each member of the proxy group to determine the amount of flotation cost incurred for each issuance and then divided those costs by each proxy company's expected dividend yield. As shown in Hevert Exhibit RBH-14, Mr. Hevert arrived at an adjustment of 0.14% or 14 basis points as a reasonable representation of flotation costs for CL&P. Although Mr. Hevert claimed that a flotation cost adjustment of 14 basis points is appropriate, he is not proposing an upward adjustment to his recommended ROE of 10.20%. Instead, Mr. Hevert considered the effect of flotation costs, in addition to the Company's other business risks, in determining where CL&P's ROE falls within his range of results. Hevert PFT, pp. 51 and 52, Exhibit RBH-14.

The OCC argued that an upward adjustment to CL&P's equity cost rate for flotation costs is not warranted. The OCC contends that this adjustment factor is erroneous for several reasons. To start, the Company had not identified any test year flotation costs for CL&P. Foremost, it is commonly argued that a flotation cost adjustment is necessary to prevent the dilution of the existing shareholders. In this case, the Company justifies an adjustment by referring to the manner in which issuance costs are recovered by including the amortization of bond costs in annual financing costs. Dr. Woolridge points out that the Company's justification for recovery of flotation costs is incorrect for several reasons. First, market-to-book ratios for the electric industry trade above 1.5x, which suggests a flotation cost reduction. Second, a flotation adjustment would be needed only in the event the market price of the stock was at/or below its book value. Third, flotation costs are primarily underwriting spreads or fees and not out-of-pocket expenses. It is the offering price, not the price the Company receives which matters to the market; therefore, the Company should not get an adjustment to the allowed return. Fourth, flotation costs would be best viewed as a transaction expense to access the capital markets. Although, CL&P wanted to be compensated for these transaction costs, the Company had not accounted for other transaction costs in determining the cost of equity, such as brokerage fees investors pay. If the Company considered brokerage fees in the DCF analysis, the stock prices would be higher and the dividend yield would be lower. This would lower the effective cost of equity. Woolridge PFT, pp. 74–76.

Mr. Hevert disagreed with Dr. Woolridge's observation that underwriter fees are not out-of-pocket expenses and that flotation costs could represent a reduction in cost of equity. Mr. Hevert disputed that the distinction is not meaningful whether fees are paid directly or through an underwriting discount, the cost results in net proceeds that are less than gross proceeds. Also, Mr. Hevert maintained that flotation costs are true and necessary costs to the issuer, and to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its required return. Hevert Rebuttal Testimony, pp. 59 and 60.

The Authority concludes that the allowance for flotation costs is reviewed on a case by case basis. Mr. Hevert calculated a 14-basis point adjustment to reasonably

represent flotation costs for CL&P, and the Authority will incorporate the 14 basis point adjustment for flotation cost in this Decision.

g. Financial Condition and Other Economic Factors

The Authority analyzed a considerable breadth of information presented in this proceeding in order to determine the appropriate return on equity to allow CL&P. Examining the testimonies, record evidence, various approaches and methodologies, as well as the financial and economic factors, the Authority is unable to substantiate maintaining the Company's currently allowed ROE of 9.40%, much less increase the ROE as proposed by CL&P. This is attributable to both the technical analysis and a variety of changes in key factors surrounding the financial setting of such a ROE. The Authority's review of the record evidence also focused on the economic and financial changes since the 2009 CL&P Rate Case, the 2012 merger of NU with NSTAR, recently awarded ROEs in Connecticut, the application of the cost of capital methods proffered by the Company and the OCC witnesses, and the Authority's assessment of each witness' recommendations and its own application of the cost of capital models as applied to the financial data in the record.

The Authority reviewed the changes to several financial and economic indicators to take account of the economic trends that have occurred since the Company's last rate case approximately four years ago. There have been several noteworthy changes in this span of time. The first is the economic recession that began in the third quarter of 2008 which resulted in steep declines to the stock market, real estate market, and dramatic increases in the number of unemployed and underemployed workers. In response to the recession, the Federal government intervened to support the banking and auto sectors in the form of bailouts, as well as to provide injections of money to state government to assist in stimulating the economic recovery. Since the time of CL&P's last rate proceeding, the Federal Reserve's asset purchases under its Quantitative Easing Policy (Federal Monetary Policy) began putting more liquidity in the market and yields fell again resulting in a higher valuation of utility stocks. The quantitative easing Part 3 of the Federal Monetary Policy began in September 2012, and is thought to have a high correlation on utility price earnings ratios. Tr. 9/10/14, pp. 1810 – 1815. The accommodative, cheap money policies and resultant low interest rate environment of the Federal Reserve Bank continue to preside, though there is discussion that these policies will likely taper off and gradually reverse should the national unemployment rate reach 6.5%.

The Company provided the following financial and economic statistics related to Gross Domestic Product (GDP), Consumer Price Index (CPI), unemployment, U.S. Treasury rates and other relevant information covering the changes in these from the time of its last rate case through the most recent quarter. This information is contained in the table below:

Table 62

Financial/Economic Indicator	2009	2013	2014 (latest day, month or quarter)*	Change 2009 to 2013	Change 2009 to Present
Gross Domestic Product (Trillions)	14,417.9	16,799.7	17,101.3	16.52%	18.61%
Consumer Price Index (CPI)	214.54	232.96	232.07	8.59%	8.17%
Unemployment Rate (National)	9.28%	7.35%	6.30%	(1.93%)	(2.98%)
Unemployment Rate (Connecticut)	8.21%	7.76%	6.90%	(0.45%)	(1.31%)
U.S. Treasury Bills (90-day)	0.15%	0.06%	0.03%	(0.09%)	(0.12%)
U.S. Treasury Bills (180-day)	0.28%	0.09%	0.06%	(0.19%)	(0.22%)
U.S. Treasury Bonds (10-year)	3.26%	2.35%	2.63%	(0.91%)	(0.63%)
U.S. Treasury Bonds (20-year)	4.11%	3.12%	3.18%	(0.99%)	(0.93%)
U.S. Treasury Bonds (30-year)	4.08%	3.45%	3.45%	(0.63%)	(0.63%)
State Allowed ROE's for utilities	10.48%	10.02%	10.23%	(0.46%)	(0.25%)
Market-to-book ratios for Industry	1.56	1.79	1.98	14.98%	27.08%
Market-to-book ratios for Peer Group	1.37	1.63	1.77	18.25%	28.73%
Dividend Yield NU	4.13%	3.47%	3.39%	(0.66%)	(0.74%)
Dividend Yield-Industry Average	4.69%	3.83%	3.42%	(0.86%)	(1.27%)

CL&P Response to Interrogatory FI-66.

Since CL&P's last rate case, it appears that the U.S. economic growth has out-paced the increase of inflation as indicated by the increase in the GDP of 18.61% while inflation as measured by the CPI only increased by 8.17%. However, the interest rates and long-term utility bond yields remain at historical low levels and are below the levels existing at the time of the Company's last rate case. Even with the strong growth seen in the GDP, interest rates remain at historically low levels. Overall, the sluggish economy and relative uncertainty still remains and is also expressed in the continued downward trend of the state authorized ROE's for utilities. Typically, the Authority would incorporate the downward trend in the 30-year long-term U.S. Treasury yields of 63 basis points to the Company's last allowed ROE of 9.40% to calculate an updated ROE of 8.77%. Although there are some signs of improvement in the economy, such as unemployment easing off its highs during the height of the recession, unemployment still remains high at 6.60% nationally and 6.90% in Connecticut. Achieving a 6.5% national rate of unemployment, which could trigger the Federal Reserve to slow its pace or reverse its accommodative monetary policy, would be highly desired but still remains ambiguous that it will occur in the near future.

The economic outlook, now for several years, has promised economic recovery and the rise of interest rates which have not occurred. It can be assumed that as the U.S. economy strengthens with the GDP growing at a rapid pace and interest rates steadily rising, cost of capital should moderately increase. However, it is not clear when, or even if, improvement in economic activity will occur. Even with the Federal Reserve market intervention known as the Quantitative Easing Policy Part 3 expected to taper off in a few months, the Open Market Committee reserves the right to change the pace of its tapering so it is uncertain exactly when or if it will finish. It is reasonable to assume that any impact of the Federal Monetary Policy on the utility stock prices and

the relative valuations will persist over time. Therefore, it is probable that the current economic condition that some suggest is a market anomaly, is the "new normal," and interest rates and capital costs will remain low over the next few years. Until there are dramatic improvements in the economy, it is reasonable to assume that these lower estimated returns will persist as long as the low equity cost environment exists.

The average ROEs for the electric and gas industries continue to trend downward as seen by the quarterly publications released by Regulatory Research Associates (RRA), Major Rate Case Decisions. At the time CL&P's last ROE was set at 9.40%, the annual average allowed ROE for the electric industry was 10.48% for 2009. For the calendar year 2013, the national average electric equity return authorized by state commission was 9.8%. This figure has further declined to 9.72% for the first six months of 2014. The Authority notes that the national average electric equity returns would still include those vertically integrated utilities that would hold a higher general risk profile than CL&P which would drive the average ROE higher. As indicated in the exhibit submitted by the OCC witness, in 2013 to 2014, there have been no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%. Woolridge PFT, p. 74 and Exhibit JRW-12. This further implies that a decrease in the ROE is warranted in this proceeding. As stated previously, commission-awarded ROEs are not purely market driven outcomes and while instructive, are not solely relied upon from a cost of capital approach.

In addition to the continued decline in authorized ROEs for electric utilities in other states' commissions, the Authority also conducted a review of Connecticut rate case Decisions since the 2009 CL&P Rate Case which allowed 9.40%. The Authority notes that these lower allowed returns transcend to other utilities as well. For example, in the Decision dated August 14, 2013, in Docket No. 13-01-19, the Authority allowed a 9.15% ROE. In Decision dated January 22, 2014, in Docket No. 13-06-08, the Authority allowed a 9.18% ROE. In the Decision dated September 24, 2013, in Docket No. 13-02-20, the resulting ROE was 9.13% excluding a water utility specific 50 basis point bonus. By the Decision dated June 29, 2011, in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules, a 8.83% ROE was granted. In the Decision dated July 14, 2010, in Docket No. 09-12-11, Application of Connecticut Water for Amended Rates, a 9.75% was granted. Likewise, in the Decision dated July 17, 2009, in Docket No. 08-12-07, Application of The Southern Connecticut Gas Company for a Rate Increase, a 9.26% ROE was granted. Given these awarded ROEs in Connecticut since 2009, the range of reasonableness is 8.83% to 9.75%, with those awarded recently in 2013 and 2014 averaging 9.15%.

The Authority also contrasts the Company's recommended ROE of 10.20% to the current economic trends and recently awarded ROEs. In reviewing the full list of all utility rate cases, in which, the Company's witness provided expert cost of capital testimony, Mr. Hevert's recommended ROE has been much higher than the actually allowed ROE awarded in every case. CL&P Response to Interrogatory FI-65. Mr. Hevert testified that it is fairly unusual for a commission to adopt any one witness' ROE. Tr. 9/10/14, pp. 1766 – 1769. Upon closer inspection of 16 of the most recent cases where Mr. Hevert provided expert testimony, all of the final authorized ROEs were below Mr. Hevert's recommended ROE ranges. Late Filed Exhibit No. 35. In fact, in this proceeding, the Authority finds that Mr. Hevert's recommended ROE range of

10.20% to 10.70% is well outside even his own results. Out of the 81 total estimates computed by the Company, only 11 of those estimates fell within Mr. Hevert's recommended ROE range for CL&P. Tr. 9/10/14, pp. 1804 – 1808.

According to Conn. Gen. Stat. §16-19tt (Decoupling Statute) and later amended with the passage of P.A. 13-298, An Act Concerning the Implementation of Connecticut's Comprehensive Energy Strategy (the Act), the Authority may consider the impact of decoupling and make any necessary adjustments to the ROE to account for a full decoupling of electric revenues from customer usage. The Authority concurs with the AG that the implementation of a decoupling mechanism further mitigates the earnings pressure of the Company having the impact of reducing the overall risk profile of CL&P. However, the record evidence does not support or quantify a specific adjustment to the ROE to account for decoupling. In fact, neither the Company nor the OCC witnesses suggested an adjustment to their recommended ROEs to quantify an impact for decoupling. These revenue stabilization mechanisms have become common in the industry and among the peer group companies selected in this proceeding. The Authority finds that revenue stabilization and cost recovery mechanisms, such as decoupling, are already reflected in current market valuations of the proxy companies. Although the Authority did not explicitly make a downward adjustment to the ROE to account for a decoupling mechanism, it confirms that a lower ROE is appropriate in this proceeding.

i. Credit Rating and Financial Metrics

From a financial viability perspective, CL&P's credit ratings and financial metrics have improved since the 2009 CL&P Rate Case. Even more significantly, the successful integration of the merger of NU and NSTAR in April 2012, momentously impacted CL&P's business and financial risk profiles and overall positive outlook by the financial community. Both S&P and Fitch upgraded CL&P's ratings due to the merger between NU and NSTAR. Since the 2009 CL&P Rate Case, the Company has increased its S&P bond rating from BBB to the present A-, two notches. As of June 24, 2014, the Company has credit ratings of A- (outlook: Positive), Baa1 (outlook: Stable), and BBB+ (outlook: Stable) from S&P, Moody's and Fitch, respectively. CL&P Response to Interrogatory FI-74. CL&P also testified that the Company is at least one notch above the average for the rest of the proxy companies. Tr. 9/10/14, pp. 1829-1832.

The Company expects to maintain its creditworthiness. The rating agencies consider a variety of factors including the regulatory environment, credit metrics such as strength of capital structure, allowed returns, earnings and cash flows in assigning ratings to any given company. The Company's S&P ratings have steadily improved in recent years as a result of NU's improved consolidated financial risk profile along with its excellent consolidated business risk profile, continued focus on controlling costs and customer service. On April 25, 2014, S&P affirmed the corporate credit ratings and revised outlooks to positive from stable of NU, CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas. CL&P Interrogatory Response to FI-53. For Moody's, evaluation of key financial metrics such as debt measurements and liquidity in earnings measurements approximates 40% of its ratings factors, while the recovery of costs and earning allowed returns account for approximately 25% of its ratings factors. The

remaining 35% are qualitative factors, such as regulatory framework and diversification. CL&P Response to Interrogatory FI-75.

According to S&P's Research Report dated April 30, 2014, S&P's positive outlook for the Company reflects the view of NU's successful merger integration. Because CL&P is a core subsidiary of NU, the positive outlook on CL&P mirrors that of NU and reflects NU's successful merger integration and effective management of regulatory risk. CL&P Response to Interrogatory FI-75. The Company has improved its financial measures due in part to the successful merger integration. From a credit perspective, recovery of the bulk of storm costs through the PURA's Storm Cost Recovery Decision is favorable as it eliminates a considerable degree of uncertainty. Overall, CL&P's business risk is viewed as excellent due in part to its low-risk regulated electric distribution and transmission operations, predictable revenue stream and efficient operations. Id.

The Company supplied key financial metrics on a consolidated basis valued at year end, December 31st, which are compiled in the table below. The forecasted figures for year-end 2014 through 2018 were filed as confidential.

Table 63

Ratio	2009	2010	2011	2012	2013
Total Asset Turnover	40.9%	36.3%	29.0%	26.3%	27.2%
Current Ratio	122.9%	106.2%	69.2%	70.9%	63.5%
Cash Flow from Operations	120.7%	99.9%	52.5%	23.0%	45.4%
Total Debt to Total Capitalization	50.9%	50.7%	51.4%	52.7%	51.8%
Times Interest Earned	3.15x	3.73x	3.56x	3.28x	4.15x
Fixed Coverage Ratio	3.05x	3.59x	3.42x	3.17x	4.01x
Cash Flow Coverage Ratio	4.3x	5.1x	3.9x	1.6x	3.7x
Operating Margin	N/A	N/A	N/A	N/A	N/A
Profit Margin	6.3%	8.1%	9.8%	8.7%	11.4%
Contribution Margin	N/A	N/A	N/A	N/A	N/A
Return on Total Assets	5.87%	6.23%	5.38%	4.78%	6.18%
Return on Total Capital	2.02%	0.52%	0.13%	1.94%	2.18%

CL&P Response to Interrogatory FI-70.

CL&P has been able to improve many key financial measures from the period ending 2009 through 2013 as indicated in the table above. Since 2009, the Company shows a stronger times interest earned ratio, fixed coverage ratio, profit margin, return on total assets and return on total capital. Although the Company's cash flow coverage, total asset turnover and cash flow from operations ratio declined since 2009, these financial ratios rebounded and significantly improved from 2012. The Company will continue to maintain its financial strength as CL&P forecasts robust financial metrics through 2018.

In general, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses, due to the essential nature of their services as well as their regulated status. Although the overall outlook for the economy as a whole has a

great deal of uncertainty and recovery has been sluggish, CL&P has been successful in navigating the credit markets due to its healthy and stable financial condition. Investment risk of public utilities is still relatively low compared to the market as a whole (1.0 beta) as evidenced by the drop in NU's beta from .80 in 2009 to .75 currently. CL&P continues to maintain a strong financial position, limited risk profile, visible forward earnings stream, a stable dividend yield, strong balance sheet and strong cash position. Despite the decline in interest rates, utilities continue to outperform most sectors of the bond market. As such, the cost of equity for the electric industry is among the lowest of all industries in the U.S. All these indicators discussed above, including the technical analysis and current market conditions, suggest a decline in the overall equity cost rate while allowing CL&P to retain its financial viability.

h. Response to Written Exceptions on Cost of Equity

In its Written Exceptions, CL&P claims that the decision to authorize an ROE of 9.17 percent is improper because it was determined using: 1) a separate "cost of equity analysis" prepared by the Authority and not subjected to review in the hearing phase of this proceeding; 2) non-record evidence, 3) factually incorrect evidence; as well as 4) "positions and evidence" gathered in an unresolved PURA docket that was closed without a Final Decision being issued. CL&P Written Exceptions, pp. 6 and 7. For these reasons, CL&P requests that the Authority reject its cost of equity analysis and set the authorized ROE at the national average of 9.48%. CL&P Written Exceptions, p. 18.

Essentially, CL&P claims that the Authority committed legal errors in setting the ROE of 9.17%by using the same method the PURA used to determine the ROE level in the UI, CNG and Aquarion rate cases and by not formally taking judicial notice of 11 publicly available data sources and 1 data source available by subscription which were data identified in Interrogatory FI-67 directed to CL&P. The Authority has routinely reviewed these data sources in past rate case proceedings, including the UI, CNG and Aquarion rates cases, and has relied on this data in past Decisions for determining ROE levels.[24]

Specifically, CL&P claims that the Authority erred by relying on certain evidence that was not administratively noticed and applying an ROE calculation methodology other than the one offered by its or the OCC's experts. CL&P claims the Authority deprived CL&P of its statutory right under Conn. Gen. Stats §§4-177c(a) and 4-178(5) to conduct cross-examination and submit rebuttal testimony to all of the evidence the PURA relied upon, including the right to cross-examine and rebut (through the use of its own witnesses) the data the Authority relied upon in its decision-making process. CL&P claims that the Authority deprived the Company of its right to cross-examine and rebut evidence because the PURA failed to properly take administrative notice of facts it

[24] Docket No. 13 06-08, Application of Connecticut Natural Gas Corporation to Increase Its Rates and Charges, Decision dated January 22, 2014, Section II.F., pp. 65-109; Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut for Amended Water its Rates, Decision dated September 24, 2013, Section II.K., pp. 74-116; Docket No. 13-01-19, The United Illuminating Company's Application to Increase Rates and Charges, Decision dated August 14, 2013, Section II.G., pp. 87-139.

relied on in its ROE analysis. Conn. Gen. Stat. §4-178 and the Regulations of Connecticut State Agencies §16-1-38(d) and (e).

As discussed in detail below, all of the data sources relied on by the Authority were contained in the evidentiary record of this proceeding. Additionally, analyses of record evidence produced by this decision-making process after the initial evidence gathering step are not themselves evidence and do not entitle a party to cross-examine their authors and rebut their accuracy. Connecticut Natural Gas Corp. v. Public Utilities Control Authority, 183 Conn. 128, 136-143 (1981). Authority staff may also advise the Commissioners regarding the appropriate methods of ROE analysis to use in its consideration of the Application. The Authority is not required to base its Decision on expert testimony offered by the applicant or other parties' experts if the Authority determines, based on its knowledge and expertise, that another method is reasonable and more appropriate. Moreover, the Authority, as an expert regulatory agency, may treat the testimony of expert witnesses as to which conclusions they would draw from facts of record as mere argument, which, if reasonable, may help the agency arrive at its Decision, and the Authority may disregard the expert testimony if it is contrary to its knowledge or experience. Thus, CL&P's expert opinion testimony regarding the appropriate evidence and analysis to rely for calculating the Company's ROE does not bind the Authority. Id.

With respect to which method to employ to review and set CL&P's ROE, the Authority has broad discretion. The PURA's enabling statute evinces a legislative intent to rely on the Authority to regulate and supervise public utilities, and to establish rates that are not unreasonable. The legislature, however, has not imposed upon the Authority any specific formula or policy to use in setting rates. In view of the remedial purpose of the statute, the lack of an express statutory formula and the evident legislative intent to rely on the Authority's expertise, the Connecticut Supreme Court concluded that the language of the enabling statute is sufficiently flexible to permit the Authority to create necessary policies to guide its rate-making decisions. Greenwich v. Department of Public Utility Control, 219 Conn. 121, 124-127 (1991); Office of Consumer Counsel v. Dep't of Pub. Util. Control, 2005 Conn. Super. LEXIS 1174, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Docket No. CV040528294S, Memorandum of Decision dated April 26, 2005, Robert F. McWeeny, J., pp. 6-10. The Connecticut Supreme Court also found that "Rate-making bodies (are not bound) to the service of any single formula or combination of formulas. The agency to which the legislative power has been delegated is free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances." Greenwich at footnote 4 citing Power Commission v. Pipeline, Co., 315 U.S. 575, 586 62 S. Ct. 736, 86 L. Ed. 1037.

CL&P had notice of the ROE methodology that the Authority applied in this proceeding to determine the Company's ROE. The Authority finds that the methodology it applied to determine CL&P's ROE of 9.17 percent is supported by past precedent in the CNG, Aquarion and UI rate cases[25] where the Authority applied the same

[25] Docket No. 13 06-08, Decision dated January 22, 2014, Section II.F., pp. 65-109; Docket No. 13-02-20, Decision dated September 24, 2013, Section II.K., pp. 74-116; Docket No. 13-01-19, Decision dated August 14, 2013, Section II.G., pp. 87-139.

methodology in setting the ROEs for those companies. The Authority developed its current ROE methodology based on comments and evidence submitted in Docket No. 09-10-06, Investigative Inquiry into the Desirability, Need and Feasibility of Establishing a Uniform Methodology for Determining Return on Equity (2009 Generic ROE Proceeding), which the Authority cites to provide guidance and clarity to parties regarding the PURA's approach to its cost of equity analysis. The purpose of referencing the 2009 Generic ROE Proceeding is to show consistency and transparency among the Authority's analysis in each rate proceeding in which the methodology has been applied.

The Authority also finds that its use of the data from particular data sources is also supported by the record and by precedent of the PURA using that data in past rate Decisions, including CL&P's last rate case.

The record supports the Authority's use of the 12 sources of financial data it relied on to determine the ROE. The Authority asked in Interrogatory FI-67, if CL&P objected to the Authority considering the following data sources, commonly relied on by finance experts, as part of the record:

a) Recent and historical US Treasury Rates (90 day, 180 day, 10 year, 20 year and 30 year) as reported in the Wall Street Journal and online at:
   1. www.bankrate.com/brm/ratewatch/leading-rates.asp
   2. www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate
   3. www.finance.yahoo.com
b) Latest Mergent Bond Guide.
c) Latest Value Line: Electric Industry Group, East, Central & West editions.
d) Latest Value Line: Summary and Index.
e) Latest Blue Chip Economic Indicators edition through end of proceeding.
f) Latest Blue Chip Economic Forecast edition through end of proceeding.
g) Latest AUS Monthly Utility Reports.
h) Ibbotson Associates, Stocks, Bonds, Bills and Inflation (SBBI) 2014 Yearbook, Morningstar Inc., 2014 edition. Including Basic Series exhibit and Determination of the Discount Rate exhibit.
i) Stock prices from www.finance.yahoo.com for companies included in proposed company peer group.
j) EPS growth estimates from www.money.msn.com for companies included in proposed company peer group.
k) EPS growth estimates from www.finance.yahoo.com for companies included in proposed company peer group.
l) EPS growth estimates form www.zacks.com for companies included in proposed company peer group.

With the exception of the Mergent Bond Record, all sources of financial data have been provided on the record and/or were publicly accessible through their Internet domains.[26] The Authority notes that the Mergent Bond Record was only relied on to

[26] *See* CL&P responses to Interrogatories FI-86, FI-87, FI-88, FI-90, FI-94,FI-95 (Bulk Filing), OCC-243, OCC-244, OCC-245 and OCC-246. Hevert PFT, Exhibits RBH-1 through RBH-15. Hevert Rebuttal

elevate the threshold to screen out those low DCF results. By removing this data source from the record, therefore eliminating the DCF screening, has the effect of decreasing the DCF ROE estimate from 9.03% to 8.47%. As explained previously in more detail, the Mergent Bond Record was used to obtain the average bond yield for each company in the proxy group. The Authority increased the minimum threshold which eliminated numerous companies that had very low DCF results, thereby increasing the average DCF ROE result.

Through Interrogatory FI-67, the Authority provided CL&P with actual notice of the data sources the Authority intended to rely on in analyzing the ROE and gave CL&P an explicit opportunity to object. In response to Interrogatory FI-67, CL&P stated that it had no objection to any of the sources listed, except the AUS Monthly Utility Reports. CL&P objected to AUS Monthly Utility Reports because "[t]he information they compile is available reliably from other listed sources, and therefore CL&P would object on this basis to PURA taking administrative notice of these reports." Response to Interrogatory FI-67. If CL&P had objected on the basis that the AUS Monthly Utility Report data was inaccurate, in some manner unreliable, or not accepted as a reliable source in the finance expert community, the Authority may have examined this objection further by cross examining CL&P's expert witness during the hearing. CL&P has not objected to the AUS Month Utility Reports on any of such basis. To the contrary, CL&P agrees that these sources of financial data are broadly published and generally used for industry purposes. These sources of financial data have been used reliably by cost of capital experts and the Authority in rate proceedings. CL&P Written Exceptions, p. 9.

The Authority finds that CL&P waived the right to object to any of the other sources cited to in FI-67.[27] The Authority also finds that CL&P is not harmed if the Company is merely claiming that the AUS Monthly Utility Report may provide repetitive or redundant data already contained in the other sources. Based on the foregoing, the Authority overrules CL&P's objection to use of the AUS Monthly Utility Reports.

Additionally, use of the data CL&P now objects to in its Written Exceptions is supported by Authority precedent in past rate Decisions. CL&P cannot now claim ignorance or surprise regarding the Authority's reliance on those data sources to determine ROE levels. For example, the Mergent Bond Guide which CL&P objects to the Authority using in its analysis was relied on by CL&P's witness and examined by the Authority in CL&P's 2010 Rate Case Decision[28] and was used by the Authority in the CNG and UI rate cases.[29] Moreover, by virtue of the Authority's Interrogatory FI-67,

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PFT, Exhibits RBH-1 through RBH-20. OCC responses to Interrogatories CL&P-2 (Bulk Filing on CD), CL&P-3, CL&P-4, CL&P-5, FI-182, FI-185 and FI-186. Woolridge PFT, Exhibits JRW-2 through JRW-14. Tr. 9/10/2014, pp. 1768 – 1771, 1779 – 1783, 1785 - 1788, 1790 – 1799, 1815 – 1817, 1822 – 1823, 1844 – 1845, and 1863 – 1865. See also, Transcript of Oral Arguments held on December 12, 2014, for numerous references to the record made by the OCC and AG during their oral arguments.

[27] In its Written Exceptions, CL&P objects to the Mergent Bond Guide for the first time on the basis that is a subscription service that is not publicly available. The Mergent Bond Guide was relied on by CL&P's witness and examined by the Authority in CL&P's 2010 rate case. Docket No. Docket No. 09-12-05 Decision, p. 97.

[28] Id.

[29] Decision dated January 22, 2014 in Docket No. 13-06-08, ; Docket No. 13-02-20, Decision dated September 24, 2013; Decision dated August 14, 2013 in Docket No. 13-01-19pp. 109, 117 and 130.

CL&P had actual notice that the Authority was going to examine and use recent data from these sources. The AUS Monthly Utility Report that CL&P objects to was also used by the Authority in the UI, CNG and Aquarion rate cases.[30]

The Authority finds that there is no merit to CL&P's claim that a "lack of a proper introduction of evidence into the record affects the computation of the ROE adopted by the Authority in the Draft because the product of the "Authority's Analysis" are the low-side values skewing the ROE to 9.17 percent." The ROE of 9.17 percent was not affected by how data sources were introduced in the record. Rather, the ROE of 9.17 percent was the correct result produced by analysis which properly took into account a full set of appropriate data sources.

Finally, CL&P did not in response to Interrogatory FI-67 or now in its Written Exceptions object on a substantive basis to the Authority's use of any data, (i.e. that data is inaccurate, the data is not reliable, the data is not the correct type of data, etc.) CL&P now sees the specific data points relied on by the Authority and has provided no substantive reason for why any of the data points should not be considered by the Authority in setting the ROE. CL&P's objection is purely procedural. CL&P, through its Written Exceptions, has been provided an opportunity to impeach, discredit or otherwise explain why the data or data sources relied on by the Authority in its ROE analysis should not be used because it is somehow flawed, inaccurate, not accepted within the financial community, etc. CL&P offered no such claims in response to Interrogatory FI-67 or in its Written Exceptions, but rather seeks to preclude the Authority from using otherwise appropriate, relevant, material and probative data based on claims of procedural harm. There is no evidence of actual procedural harm to CL&P since it had actual and constructive knowledge that the Authority would rely on recent versions of these data sources. Based on Interrogatory FI-67 as well as the Authority's recent rate case decisions for CNG, UI and Aquarion, CL&P had actual and constructive notice that the Authority would review and probably rely on these data sources to set the ROE. The Authority further finds that CL&P suffered no actual prejudice due the fact that all but one of the sources is publicly available.

In its Written Exceptions, CL&P claims that there are three components that are legally and factually deficient and cannot be relied upon. CL&P Written Exceptions, pp. 11 and 12. First, CL&P claims that the value of 8.77% as an update to the last rate case is nowhere in the record and has not been presented for review or cross examination. As indicated previously in the Decision, the 8.77% simply reflects the decline in the 30-year long-term U.S. Treasury yields of 63 basis points to CL&P's last allowed ROE of 9.40% (9.40% - 0.63% = 8.77%). The Authority typically makes this simple calculation to use as another benchmark or parameter to indicate in which direction the current allowed rate should trend. Although the drop in the interest rates is much more pronounced than the decline of the state authorized ROEs, the overall downward trend in returns is evident. This benchmark was also used by the Authority in the recent UI and CNG rate case Decisions.

[30] Decision dated January 22, 2014 in Docket No. 13-06-08, p[p. 68 and 70; Decision dated September 24, 2013 in Docket No. 13-02-20, pp. 82, 91, 99 and 115.

Second, the Company claims that the statements made in the draft that a 6.5% national rate of unemployment and a change in Federal Reserve policy to reverse its monetary policy would be highly desired but still remains ambiguous that it will occur in the near future, are factually incorrect. CL&P Written Exceptions, pp. 12 and 13. The Authority finds that these statements are correct and refers the Company to review the lengthy discussions cited in the transcript.[31] At the time the Authority drafted this Decision and the record was closed, it was still unknown if or when the Federal Reserve would reverse its accommodative monetary policy. The Authority agrees that the steady decline in the national unemployment and the reversal of the Federal Monetary Policy is highly desirable and supports an improvement in the economy. However, as the Authority stated in that section of the Proposed Final Decision, there are also other indicators such as continued decline in interest rates, low long-term bond yields, downward trend of the state authorized ROEs for utilities, and the relative uncertainty still remains.

Lastly, the Company contends that the DCF and CAPM analysis computed by the Authority used financial data not on the record for the proceeding and the entire computational analysis not made available to the Company or other parties in this proceeding. CL&P Written Exceptions, p. 13. As discussed above, the Authority finds that its use of the sources of financial data is clearly supported by the record, as well as precedent of the Authority using that data in past rate Decisions. Without a specific reference by CL&P to the computational analysis, the Authority finds that the record is clear regarding the PURA's computations based on the narrative description regarding the process, methods, computation and sources of financial data used in the Authority's analysis.

The Company's request that the Authority reject the proposal in the Decision and set the authorized ROE at the national average of 9.48% is unreasonable. Since the ROE is a market-based concept, jurisdictionally allowed returns should not be relied upon as a proxy from a cost of capital approach. To simply ignore all the relevant financial data and current market analysis compiled by all the cost of capital witnesses in this proceeding, is not keeping with the fundamental standards that returns should be commensurate with the returns expected of enterprises having comparable risks. The Authority's analysis is reflective of the record and corresponds as closely as possible to the current market conditions and expected returns.

i. Conclusion on Cost of Equity

In determining the cost of equity, the Authority considered all of the witnesses' cost of equity analyses by integrating some of the methods in its own evaluation. Consistent with past practice, the Authority relies on the results of the constant growth DCF and simplified CAPM methods in its analysis. Typically, the Authority weighs the DCF model more heavily in its analysis. However, in this case the weighting of the methodologies had no influence on the final result since the DCF and CAPM estimates were identical. The Authority also used its analysis that updated the last Company rate case and the survey of recent Decisions merely to establish benchmark parameters and

[31] See Tr. 9/10/14, pp. 1810 - 1815.

to indicate in which direction the current allowed rate should trend. The Authority has not incorporated an explicit downward adjustment to ROE for the implementation of a full decoupling mechanism, given that the majority of its peer companies have some form of a revenue stabilization cost structure embedded into their cost of equity valuations. The Authority recognizes that these mechanisms reduce the risk of the Company and contribute to lower expected returns. Consequently, in regulating CL&P to allow a return commensurate with the current economic conditions, the Authority has determined that investors expect less of a return today than in 2010, when the return was established at 9.40%. The Authority finds that the Company has strengthened its financial capability and has less risk, both financially and operationally, which provides further support that CL&P is performing well in an environment that expects lower returns.

The table below represents a summary of the Authority's analyses and findings with respect to the ROE.

Table 64

Method	Authority Result
Update Last Rate Case (decline interest rates)	8.77%
RRA Average Allowed ROE as of June 2014	9.72%
2014 Average Distribution-Only ROE	9.48%
Survey Connecticut Allowed ROEs: Average Awarded in 2013 and 2014	9.15%
DCF	9.03%
CAPM	9.03%
Utility Risk Premium	Not Used
Indicated ROE	9.03%
Adjustment for Flotation Cost	.14%
Allowed ROE	**9.17%**

Based upon the implementation of several of the principles detailed from the 2009 Generic ROE Proceeding, the Authority notes that the methodologies have become more transparent and less "black box." Likewise, the application of the process with the present data has narrowed the range of reasonableness. An ROE of 9.17% is indicated by the analysis and the cost of capital measures employed by the Authority is incorporated into its weighted cost of capital assessed below.

j. Authority's Allowed Weighted Cost of Capital

Consistent with the legal guidelines defined in Conn. Gen. Stat. §16-19e(a)(4), the Authority identified a rate of return on the rate base that is deemed appropriate for the Company's overall capital structure. The Authority has recognized the key components of the Company's capital structure, estimated the cost of each component of capital, and then calculated its overall cost of capital by weighting each component cost by its proportionate share of the overall capital structure.

After study and deliberation of all cost of capital issues presented in this proceeding, the Authority finds that 7.31**%** is a fair rate of return, reflecting a return on equity of 9.17**%**. The table below summarizes the approved capital structure components, capital costs and calculates the weighted cost of capital, including the 9.17**%** assigned ROE, determined by the Authority based upon the 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt capitalization.

Table 65
Allowed Weighted Cost of Capital

Class of Capital	Ratemaking Percentage	Embedded Cost	Ratemaking Weighted Cost
Long-term Debt	47.61%	5.45%	2.59%
Preferred Stock	2.01%	4.80%	0.10%
Common Equity	50.38%	9.17%	4.62%
Total Capitalization	100.00%		7.31%

The Authority finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for the Company to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

4. ROE Penalty

In late August, 2011, Connecticut was struck by Tropical Storm Irene (Storm Irene). In late October, 2011, Connecticut was struck by an early snowstorm (October Snowstorm). Storm Irene and the October Snowstorm (the 2011 Storms) resulted in extensive interruptions to electric service. The Authority opened Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms, to investigate the Company's (and other utilities') response to the 2011 Storms.[32] The Decision dated August 1, 2012, in the above captioned proceeding states as follows:

> . . . [t]he Connecticut Light and Power Company's performance in the aftermath of the 2011 storms was deficient and inadequate in the areas of outage and service restoration preparation of personnel, support of its municipal liaison program, development and communication of restoration times to customers, and overall communication to customers, other service providers and municipalities, as to warrant regulatory sanction. In this Decision, the Public Utilities Regulatory Authority also concludes that because of The Connecticut Light and Power Company's failure to obtain adequate assistance in advance of the October 29, 2011 storm, its response to that storm was deficient. Because of The Connecticut Light

[32] Docket No. 11-09-09 was initially opened in September, 2011 to investigate response to Tropical Storm Irene. After the October Snowstorm, the scope was expanded to include that event.

> and Power Company's failure to adequately fulfill its duties imposed by law and to adequately and suitably provide for the overall public interest with regard to these particular areas of performance, the Public Utilities Regulatory Authority establishes in this Decision, a rebuttable presumption that The Connecticut Light and Power Company should have imposed on it, an appropriate reduction to its allowed return on equity in its next ratemaking proceeding as a penalty for poor management performance and to provide incentives for improvement. . . In considering the appropriate reduction to allowed returns on equity in forthcoming ratemaking proceedings and in exercising its jurisdictional approval for recovery of appropriate 2011 storm costs, the Authority will consider and weigh the extent to which CL&P has recognized its shortcomings and taken concrete and measurable steps to embrace the need for aggressive, extensive restructuring of both its attitude toward storm management and establishment of new practices for execution of future storm response.
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> Decision, p. 1.

The Authority took administrative notice of the record evidence presented in Docket No. 11-09-09 and the following consultant reports prepared in connection with the review of CL&P's storm response as well as the Report of the Two Storm Panel: Witt Associates Report; Report of the Two Storm Panel; Liberty Consulting Group; and the Davies Report. Notice of Taking Administrative Notice dated September 3, 2014.

CL&P stated that there is no basis for sanctioning it for its performance in the 2011 Storms. The Company asserted that it has met every applicable requirement relating to storm performance. The Company also asserts that the Authority's investigations and rulings to date support the fact that CL&P's response to these storms was reasonable under the circumstances. CL&P stated that the reasonableness of its actions can be confirmed in two ways. First, the Authority's Decision dated March 12, 2014 in Docket No. 13-03-23 (March 12, 2014 Decision), did not find CL&P to be imprudent, nor did that Decision disallow any costs related to any of those areas. Second, the evidence described in Bowes PFT, Exhibit KBB-3 demonstrates that CL&P's conduct in these areas was reasonable under the circumstances. Finally, CL&P stated that it has made concrete and measurable improvements in relation to its emergency preparedness and response function, as described in Bowes PFT, Exhibit KBB-4. Bowes PFT, pp. 43-45.

The OCC believes that the Authority should impose a 35 basis point penalty on CL&P for its imprudence in responding to the 2011 Storms. Although the OCC recognizes that CL&P has taken a variety of steps to increase the resilience of its distribution system and otherwise improve its storm response, the OCC argues that an ROE penalty is still appropriate because the Company did not adequately prepare and respond to the 2011 Storms. Furthermore, according to the OCC, the prudence standard requires that a utility's actions must be evaluated within the context of information that was known at the time the actions were taken, not after the utility has had an opportunity to remedy any harm that occurred at ratepayer expense. Finally, the OCC cites evidence submitted in Docket No. 13-04-07, PURA Investigation into Allegations that The Connecticut Light and Power Company Impaired and Impeded

PURA's Investigation of CL&P's Response to the October 2011 Nor'easter, as demonstrating that CL&P deliberately withheld accurate power restoration time estimates from the public. OCC Brief, pp. 33-38.

The AG also believes that the Authority should impose an ROE penalty on CL&P for its performance in the 2011 Storms. The AG notes that the Authority established a rebuttable presumption in its Decision in Docket No. 11-09-09 that CL&P should have imposed upon it an appropriate reduction to its ROE in this rate case. The AG cited to findings in the Liberty Report on the 2011 Storms performance that was submitted by the Authority's consultant in Docket No. 11-09-09, and other extensive record evidence in that docket as confirming the Company's inadequate performance in preparing for and responding to the 2011 Storms. Similar to the OCC, the AG asserted that the Authority should impose an ROE penalty of 35 basis points on the Company for its 2011 Storms response regardless of the subsequent demonstrated improvements, since the penalty was intended to be imposed on that basis. The AG next noted that the Authority has previously imposed financial penalties on other utilities that have exhibited poor management performance, and provides cites to those dockets. Finally, the AG stated that, absent the Company's subsequent improvements, it would have advocated for stronger penalty. AG Brief, pp. 23-30.

In the Decision in Docket No. 11-09-09 and restated in the March 12, 2014 Decision, the Authority indicated that it intended to review, in this rate proceeding, the issue of whether or not CL&P's ROE should be reduced to reflect deficiencies in response to the 2011 Storms. Such a review is appropriate in this rate proceeding as the Authority is charged with setting just and reasonable rates after specifically examining and determining the appropriate level and structure of rates charged customers that shall reflect, along with other considerations: 1) prudent and efficient management of the franchise operation, and 2) that public service companies shall perform all of their respective public responsibilities with economy, efficiency and care for public safety and energy security. Conn. Gen. Stat. §16-19e(a)(3) and (5).[33] The

[33] Conn. Gen. Stat. §16-19e, which governs the Authority's regulation of internal utility management and rate structures, states: 16-19e(a) In the exercise of its powers under the provisions of this title, the Public Utilities Regulatory Authority shall examine and regulate the transfer of existing assets and franchises, the expansion of the plant and equipment of existing public service companies, the operations and internal workings of public service companies and the establishment of the level and structure of rates in accordance with the following principles: (1) That there is a clear public need for the service being proposed or provided; (2) that the public service company shall be fully competent to provide efficient and adequate service to the public in that such company is technically, financially and managerially expert and efficient; ***(3) that the authority and all public service companies shall perform all of their respective public responsibilities with economy, efficiency and care for public safety and energy security,*** and so as to promote economic development within the state with consideration for energy and water conservation, energy efficiency and the development and utilization of renewable sources of energy and for the prudent management of the natural environment; (4) that the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs including, but not limited to, appropriate staffing levels, and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable which shall include, but not be limited to, reasonable costs of security of assets, facilities and equipment that are incurred solely for the purpose of responding to security needs associated with the terrorist attacks of September 11, 2001, and the continuing war on terrorism; ***(5) that the level and structure of rates***

Authority has reserved for this proceeding consideration of an ROE reduction related to poor performance in 2011.

In this proceeding, CL&P has the burden of proving both its rate proposal is just and reasonable and that its management of storm-related actions in 2011 and going forward were and are appropriate. Conn. Gen. Stat. §16-22; Decision in Docket No. 11-09-09 and March 12, 2014 Decision. CL&P's customers have a right to expect that CL&P performed in 2011, and will perform in the future, its public service duties in a prudent, efficient, safe and adequate manner. See generally, Conn. Gen. Stat. §§16-11, 16-19e, and 16-20. Part of CL&P's burden of proof in a rate case was to show that it has and will properly fulfill its duties.

Based on its findings in Docket No. 11-09-09, the Consultant Reports and other evidence contained in the record in this proceeding and taking into account CL&P's position that it acted prudently in both storms, the Authority finds that CL&P fell short of reasonably fulfilling its duties with respect to the 2011 Storms. The Authority further finds that CL&P's management needs to work toward eliminating past deficiencies and gross inefficiencies and to demonstrate more "prudent and efficient management" with actual improved future storm preparation response performance at a level at or above good utility practice. Further, the Authority finds that CL&P must not repeat its past deficient level of performance and improve the performance of "public [storm response] responsibilities with respect to economy, efficiency and care for public safety and energy security" at or above the level of acceptable utility practice standards.

Contrary to CL&P's assertions, the Authority concludes that it is not required by Conn. Gen. Stat. §16-19e(a)(3) and (5) to make any explicit findings of past imprudence in order to set the going forward ROE for CL&P. If the Authority were going to disallow cost recovery, the Authority would be required to make a finding of imprudence to support the disallowance. In the Decision in Docket No. 11-09-09 dated August 1, 2014, the Authority specifically tied its discussion of prudency to the issue of CL&P's future recovery of storm-related costs. Decision, Section III.A.3, p. 18. The Authority did not state that the prudency issue or prudency determination had any relevant relationship to the Authority's future determination regarding an appropriate ROE level for CL&P. Decision, Section III.A.4, 18-19.

With respect to setting an appropriate ROE in this proceeding, the Decision in Docket No. 11-09-09 stated that the Authority would examine whether to impose an "appropriate basis point reduction to CL&P's allowed return on equity (ROE) for such poor management performance and to provide incentives for improvement." As CL&P recognizes, the Authority is not ordering the disallowance of storm-response-related cost recovery in this proceeding. Therefore, prudence is not at issue. Instead, the Authority is 1) reviewing the history of CL&P's 2011 storm response performance and CL&P's subsequent actions in that regard; 2) making determinations based on the

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charged customers shall reflect prudent and efficient management of the franchise operation; and (6) that the rates, charges, conditions of service and categories of service of the companies not discriminate against customers which utilize renewable energy sources or cogeneration technology to meet a portion of their energy requirements. [Emphasis added].

factors listed in Conn. Gen. Stat. §16-19e(a)(3) and (5); and, 3) reflecting those determinations in establishing a just and reasonable future ROE level for CL&P.[34]

With respect to Conn, Gen. Stat. §16-19e(a)(3) and (5), the Authority finds that the record evidence from Docket No. 11-09-09 and this docket fully, as described herein, supports the Authority's determination that CL&P's storm response was inadequate and deficient sufficient to warrant implementation of a rate making ROE reduction incentive to signal the need for improved management performance with respect to past and future storm responses. The Authority's consultant, The Liberty Consulting Group (Liberty) found that "CL&P's storm performance was below average." Liberty Report, 1. Liberty cited to failures in CL&P's tree trimming program, its restoration estimates, its management command system, its ability to acquire outside resources and its coordination with towns as all deficient. Liberty Report, 1 and 2. CL&P did not seek meaningful outside resources until after the storm hit and caused numerous service outages. Liberty Report, p. 78; Davies Report, p. 21.

In addition, CL&P's Emergency Response Plan (ERP) did not adequately stress training and drills. Liberty Report, pp. 13 and 18. CL&P employees questioned the plan and its application during the 2011 Storms and suggested that it was written for regulators, was not applied during the 2011 Storms, lacked adequate specificity and that while it may have worked on paper, it was not the subject of adequate training. Liberty Report, pp. 18-19. There is no evidence that CL&P drilled or exercised its ERP for at least five years prior to the 2011 Storms. Witt Report, p. 17.

The Authority finds that there was also substantial evidence in the record of Docket No. 11-09-09 that CL&P's municipal liaisons were poorly prepared, poorly

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[34] Notwithstanding this determination, the Authority finds that CL&P's 2011 Storm preparations and responses were imprudent. The Authority applies a three-part test is as follows: "First, there must be a clearly understood definition of the standard of care by which a utility's performance can be measured. Second, the actions of the utility must be examined to determine if there has been a failure on its part to conform to the standard required. Finally, there must be a reasonably close casual connection between the imprudent conduct, if any, and actual loss or damage. Applying this test, the Authority finds that CL&P was imprudent for failing to act as a reasonably prudent utility in the following ways: 1. CL&P inadequately prepared for major storms, and failed to exercise or drill its emergency response plans and evaluate the results for at least five years prior to the storms; 2. CL&P failed to request the assistance of outside crews in a timely manner and failed to reasonably manage the crews that arrived; 3. CL&P engaged in an unreasonable damage assessment process, including failure to transmit assessment information from the field to operations headquarters efficiently; 4. CL&P failed to train and support municipal liaisons and defer to local restoration priorities; 5. CL&P failed to reasonably develop estimated restoration times; and 6. CL&P failed to reasonably manage communications with the public and public officials concerning restoration times. As a result of the aforementioned imprudent conduct, CL&P's customers suffered tangible great economic losses, including but not limited to lost food, medicine, and income and added expenses for hotels and other items purchased to survive the storm and cold weather conditions during outages. CL&P's customers likewise suffered substantial intangible harms, including but not limited to great levels of inconvenience, uncertainty, and discomfort. The Authority finds that the various storm reports contained in the record and the Briefs and Reply Briefs of the AG and OCC filed in this proceeding appropriately describe CL&P's imprudent conducts and the resulting harm to customers. The Authority declines to articulate further on this imprudence finding given that "imprudence" is not a necessary statutory finding for the Authority to make in reducing the ROE pursuant to Conn. Gen. Stat. §16-19e(a)(3) and (5).

supported and often ineffective. The results of CL&P's unpreparedness and mismanagement were disastrous for the affected towns and their citizens. Docket No. 11-09-09, Werbner Pre-Filed Testimony, p. 3. Elected representatives from the towns of Simsbury, South Windsor, Tolland, Redding, Newtown, and Ridgefield appeared before the Authority and testified concerning CL&P's failures and the impacts on their towns. Decision in Docket No. 11-09-09, pp. 5-9. For example, CL&P could not tell Tolland leaders where Company crews were working, where the outages in town were, or provide real-time progress reports on restoration. Werbner PFT, p. 4. CL&P's inability to provide accurate restoration projections "had a material adverse impact on the town's ability to protect the health and safety of town residents." Glassman PFT, p. 5. Simsbury had no accurate information on which to schedule its shelter operations and care for its elderly and disabled. Id.

The Authority received more than one thousand written complaints and an additional one thousand telephone calls from customers concerning CL&P's deficient and inadequate response to the 2011 Storms. PURA stated that:

> [t]he majority of the customers who were affected by the 2011 Storms were concerned with the length of time it took the companies to restore service and the difficulty receiving information from the companies. Several customers stated that the companies were unprepared, mismanaged, and had underestimated the magnitude of the storm by not having sufficient repair crews available. Consumers believed that the lack of information provided by the companies left them unable to prepare for a longer than normal outage.
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> Customer comment varied, but frustration regarding the amount of time the utility companies required to repair and restore service was a common theme. Several customers mentioned that Connecticut has the highest electric rates in the country and therefore, warrants better customer service. Customers suggested ways to help avoid future outages such as trimming trees and burying power lines. Others felt that customers with wells or septic systems should have their restoration of service prioritized because of the public health issues.
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> Decision in Docket No. 11-09-09, p. 5.

CL&P's unreasonable level of preparedness and its failure to respond to the 2011 Storms in a reasonable manner caused the service restoration process to take longer than it otherwise would have. The failure of the municipal liaison program, as well as the delay in restoration for many customers, caused the towns to incur significant additional costs. Docket No. 11-09-09, Tr. 5/20/12, pp. 409-14. CL&P's management deficiencies with respect to the October Snowstorm, turned extended power outages into crisis situations, caused significant public anxiety and severely impacted residents' and towns' abilities to deal effectively with the outages.

Based on the foregoing, the Authority concludes that CL&P's performance in response to the 2011 Storms was deficient and inadequate and that the rates approved in this proceeding must encourage better storm response performance by CL&P

management. Therefore, the Authority will employ its authority under Conn. Gen. Stat. §16-19e(a)(3) and (5) to reduce the Company's ROE of 9.17% by 15 basis points for a period of one year to incent CL&P's management to show actual improvements in future storm responses. The ROE penalty of 15 basis points imposed on the Company for the Rate Year will reduce the revenue requirement by $4.394 million. Because the penalty will be in effect for the Rate Year only, the Authority will not require that Rate Year rates be designed to reflect the penalty. Instead, the adjustment will be made to the allowed revenue requirement target in the Company's first decoupling mechanism reconciliation. In following years, the Company may true-up to its full allowed revenue requirements. The Authority directs the Company to include the adjustment for the ROE penalty in its Rate Year decoupling mechanism reconciliation filing.

If CL&P fails to improve based on major storm preparedness and response and is found not to be in compliance with the outage restoration standards established by the Authority's November 1, 2014 Decision in Docket No. 12-06-09, PURA Establishment of Performance Standards for Electric and Gas Companies, the Authority may impose penalties as defined in that Decision and reduce CL&P's going forward ROE to create an incentive for CL&P to improve its performance.

The Authority recognizes that, subsequent to the 2011 Storms, CL&P has been required by statute and PURA decisions to implement certain proactive measures aimed toward improving CL&P's storm response performance. The Authority, as described below, has accounted for these improvements in determining an appropriate ROE reduction. The Authority also recognizes, however, that the real test of whether CL&P's storm performance will meet and exceed acceptable standards is by reviewing CL&P's actual future performance. Therefore, pursuant to its authority under Conn. Gen. Stat. §16-19e(a)(3) and (5), the Authority finds that it is just and reasonable in setting the structure and level of CL&P's rates to take into account evidence from recent past poor, deficient, imprudent and inefficient management performance with respect to storm response and create an incentive for CL&P to ensure that it attempts to improve its future management performance regarding future storm response. ROE adjustments such as the one implemented by the Authority in this Decision ensure that rates reflect prudent and efficient management. Conn. Gen. Stat. §16-19e(a)(5). Similar adjustments that have been upheld on appeal have been made by the Authority[35] and state public utility commissions in other jurisdictions.[36]

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[35] Conn. Natural Gas Corp. v. Conn. Dep't of Pub. Util. Control, 2010 Conn. Super. LEXIS 19, 17 (Conn. Natural Gas Corp. v. Conn. Dep't of Pub. Util. Control, CV094021664S, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Memorandum of Decision dated January 6, 2010); Southern Conn. Gas Co. v. Conn. Dep't of Pub. Util. Control, 2010 Conn. Super. LEXIS 788, 19 (Southern Conn. Gas Co. v. Conn. Dep't of Pub. Util. Control, CV094021665S, Superior Court of Connecticut, Judicial District of New Britain at New Britain, Memorandum of Decision dated April 1, 2010).

[36] In re Citizens Utilities Company, 171 Vt. 447, 769 A.2d 19 (2000); US West Communications, Inc. v. Utilities & Transportation Commission, 134 Wn.2d 74, 949 P.2d 1337, 1358-1362 (1997); Mountain Fuel Supply Company v. Public Service Commission of Utah, 861 P.2d 414 (1993); Gulf Power Co. v. Wilson, 597 So. 2d 270, 270-274 (1992); Wisconsin Public Service Corp. v. Public Service Commission of Wisconsin, 156 Wis. 2d 611, 457 N.W.2d 502 (1990).

Specifically, the Authority finds that reducing the base ROE of 9.17% by 15 basis points to an ROE of 9.02% for the period 2015 is just and reasonable. For purposes of tracking ESM sharing and overearnings under Conn. Gen. Stat. §16-19(g), the Authority will base these calculations on an ROE of 9.02%. The primary purpose of the ROE reduction is to provide an incentive for CL&P to improve its storm response performance. If CL&P improves its future storm response performance, CL&P's ROE will not be subject to such reductions in the future.

If during the Rate Year, CL&P's storm response performance triggers the Authority to reopen this proceeding and find deficiencies in CL&P management's performance regarding storm response meriting extension of the ROE reduction, as determined by any proceedings opened to determine CL&P's compliance with the Docket No. 12-06-09 standards, the Company's ROE will remain at 9.02%.

In determining the allowed base ROE of 9.17% using the Authority's approved methodology, the Authority examined the testimonies, record evidence, various approaches and methodologies proffered by the Company and OCC witnesses, as well as the financial and economic factors in this proceeding. The Company had provided numerous ROE estimates that resulted in an expansive range from a low of 7.58% to an astronomical 12.51%. The OCC witness calculated a narrower ROE range of 7.80% to 9.0%. To test the results of the Company and OCC witnesses, the Authority conducted its own cost of equity analysis consistent with the methodologies exercised in past practice resulting in an allowed ROE of 9.17%. According to data from Regulatory Research Associates, the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Again, an ROE of 9.02% generated by the ROE penalty of 15 basis points, is supported within the general trend of interest rates and nationally authorized ROEs. The Authority notes that the reduced ROE of 9.02%, including the ROE penalty, falls within a range of ROEs determined by others to be reasonable for other utilities as well as the Company's and the OCC's limited range of ROE estimates. Setting the authorized return, inclusive of the reduction, should allow the Company to maintain its credit and financial integrity and will enable it to acquire sufficient new capital at reasonable terms to meet its service requirements.

The Authority finds that the 15 basis points ROE reduction is reasonable compared to previous reductions it has ordered in past proceedings. For example, in Docket No. 10-09-08, Application of United Water Connecticut, Inc. to Amend Rate Schedules, dated April 27, 2011, the Authority imposed a fifty basis points ROE reduction for imprudent management. In that case, the Authority found that the United Water Company's accounting, record keeping and billing methods were lacking and imposed the fifty basis point downward reduction to its ROE "as a penalty and strong warning to improve its business management practices." Id., 83.

Similarly, in the Decision dated June 30, 2009 in Docket No. 08-12-06, the Authority found that CNG did not properly include certain charges in its bills, found that the company's management that oversaw billing and rates was imprudent, and imposed a 10 basis point reduction to its return on equity as an imprudence penalty. The Authority noted in that case that such ROE adjustments are designed to ensure that

rates reflect prudent and efficient management as required by Conn. Gen. Stat. §16-19e(a)(5).

In other cases, the Authority has repeatedly imposed substantial cost recovery disallowances where it has found CL&P acted imprudently. See Decision dated July 30, 1997 in Docket No. 96-10-06, DPUC Investigation Into Whether The Connecticut Light and Power Company Fulfilled its Public Service Responsibilities with Respect to its Nuclear Operations (imprudence disallowance of $600 million in replacement power costs due to shutdown of Millstone reactors / disallowance of additional $360 million in other incremental costs); Decision dated February 13, 1992 in Docket No. 90-02-03, Connecticut Yankee Nuclear Plant Shutdown (imprudence disallowance of $31,269,000 in replacement power costs for shutdown of Millstone reactor); Decision dated December 30, 1992 in Docket No. 91-10-02, DPUC Investigation into the Millstone 1 Shutdown on October 4, 1990 (imprudence disallowance of $2,865,000 in replacement power costs for shutdown of Millstone reactor).

The Authority finds that CL&P's mismanagement of its major storm response in 2011 merits a more severe ROE reduction than the 10 basis points reduction imposed on CNG and possibly the 50 basis points reduction imposed on United Water because more CL&P customers were negatively impacted and to a much greater degree by the extended outages following the 2011 Storms than customers were by the billing errors in the 2009 CNG matter or the accounting errors in the 2011 United Water matter. The OCC and AG each requested a 35 basis points reduction. The 15 basis points reduction falls within the range of these two past similar management-performance-based ROE reductions and is on the lower end of the 10 to 50 basis points range to reflect the steps CL&P has already taken since the 2011 Storms to be better prepared to respond to future storms.

The Authority may have assessed a greater reduction to CL&P's ROE, if the Authority did not find that the Company has demonstrated a strong commitment to improving storm performance as demonstrated by its improvements in storm response protocols (such as pre-staging practices), emergency planning, and storm resiliency measures, all widely documented in this and a number of other PURA proceedings. Furthermore, improvements in emergency preparedness and response practices were confirmed in the Authority's Decision dated August 21, 2013 in Docket No. 12-11-07. No parties or intervenors have argued that the CL&P storm response practices have not improved since the 2011 Storms.

While the Authority finds that the extent of CL&P's improvements in storm resiliency measures weigh strongly against a larger ROE reduction, the Authority finds there remains a need to penalize CL&P and incentivize it to improve its future storm performance to avoid a repeat of the mismanaged and deficient performances that occurred in response to the 2011 Storms. The Authority notes that, but for the major improvement in CL&P's storm preparedness and response subsequent to the 2011 Storms, the ROE reduction would have been substantially higher.

G. MERGER SAVINGS

In the Merger Decision, the Authority approved the merger agreement between Northeast Utilities and NSTAR, stating that it was in the public interest. Merger Decision, p. 48.

A condition of the merger settlement agreement provided that any future recovery of transaction costs is subject to Authority review and approval in a future rate proceeding. Merger Decision, Attachment A, Article 5.3. The instant docket is the first rate case since the merger was approved; therefore, the Authority will review the costs and merger savings associated with the merger.

The Authority found in the Merger Decision that total net benefits of approximately $783.8 million were expected on an overall, enterprise-wide basis with an estimated 38.5 percent of that amount, or approximately $301.8 million, allocable to CL&P's transmission and distribution operations based on 2011 financial data. The companies provided the analysis of savings through a Merger Integration Report (MIR). The Net Benefits Analysis was developed by analyzing the current cost structures of NU and NSTAR, with total actual labor costs disaggregated into nine principal functional areas for analysis. The savings quantified in the Net Benefits Analysis were estimated on the basis of potential reductions in labor and non-labor costs within corporate and administrative functional areas. For non-labor cost savings, the companies examined actual costs in 17 potential areas of savings, including 13 categories of corporate and administrative costs (e.g., insurance, facilities, benefits and fleet costs) and 3 categories of purchasing costs (procurement, inventory and contract services). The same methodology was used to quantify merger-related savings in this case. Mahoney PFT, pp. 6 and 7. The Company submitted an updated MIR summarizing the areas of savings, updated through June 1, 2014. Mahoney PFT, Exhibit MJM-2A. The updated MIR forecasts an increase, from the amount presented in Docket No. 12-01-07, in merger savings on an enterprise-wide basis of $92.8 million for a total of $876.6 million. Id., p. 4.

The Company stated that over the 10-year post-merger period, that the MIR covers, the generated savings will far outweigh the costs incurred to complete the merger. The merger integration report indicates total estimated merger-related costs of $119.4 million. Mahoney PFT, Exhibit MJM-2A, p. 4. The Company proposes to share costs associated with the merger based on the same percentage that savings are allocated. The Company proposes to amortize this amount over 10 years, without a return. The CL&P portion of the $119.4 million is calculated at $25.204 million in total or $2.520 million annually for ten years. Application, WP C-3.34, p. 3. In justification, the Company stated that the projected cumulative net merger-related savings of $876.6 million are significantly higher than the costs incurred to complete the merger. PFT Mahoney, pp. 7 and 8.

Article 5.3 of the settlement agreement in the Merger Decision states the following:

> Merger related payments made to officers leaving the employ of NSTAR, NU, any of the temporary or surviving entities engaged in the proposed merger transactions, the operating companies, or their successors (together, the "post-merger organization") in the

> category of “change of control” payments, or to executives remaining with the post-merger organization in the category of “retention payments,” shall be recorded at the parent company level upon the merger close and shall not be eligible for recovery as a merger related cost or otherwise from customers.

The Authority reviewed the expense items that the Company is claiming as merger-related costs and finds that CL&P has appropriately removed the above stated payments from costs associated with the merger in accordance with the settlement agreement. The Company has also verified exclusion of these payments through responses to interrogatories and testimony, including the response to Interrogatory AC-45.

With regard to the remaining expense items that compose the $119.4 million, the Authority has reviewed these items and notes that they include amounts for: legal fees, bankers’ fees and non-executive separation costs. Response to Interrogatory AC-114. These items are customary and can be expected to be incurred in this type of transaction. The Authority therefore approves of the items to be included for cost recovery.

No party addressed this issue in its brief or reply brief.

The Authority agrees that the merger has provided benefits to customers which exceed the costs to achieve those reductions. The Authority therefore approves the Company’s request to amortize the CL&P portion of merger costs of $2.520 million annually for 10 years.

In terms of going forward merger costs and savings that the Authority can expect to see in future CL&P filings, the Company stated:

> I guess what we would see moving away from this rate case is our ability to retain those merger savings that we have already achieved at this point. I believe after this rate case, while we'll have merger savings by holding onto the savings that we've achieved over time, I wouldn't go as far as to say that the attrition going forward through 2017 will be related to the merger. At some point, and I believe at this point with the rate case, we will start to look at things as business as usual and that just acquiring more efficiencies. To the extent, as Mr. Chung explained earlier, that these efficiencies would have occurred only but for the merger, then we will recognize them as merger related.
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> Tr. 9/5/2014, pp. 1445 and 1446

At the conclusion of this rate case and going forward, the Company should move from identifying items that could be considered merger related towards a business as usual approach. In the Company’s next filing, the Authority expects to see little to no claim for merger-related initiatives or cost recovery. Future efficiencies should be

attributed to management initiatives under a business structure that will have been in place for over five years at the time of the Company's next rate filing in 2017.

H. DECOUPLING

The Authority approves the same decoupling mechanism for CL&P as it approved for UI. This decoupling mechanism provides for customers to pay the Company for any under-collection of revenues and that CL&P credit back any over-collection of revenues. CL&P may not retain any revenues. See, Decision dated February 4, 2009 in Docket No. 08-07-04, Application of The United Illuminating Company to Increase its Rates and Charges, pp. 126 and 127; Decision dated September 1, 2010 in Docket No. 08-07-04RE02, Application of The United Illuminating Company to Increase its Rates and Charges - Review of Decoupling Pilot, Pension Tracker, ROE Sharing Mechanism, and GET Adjustment, p. 9; Decision dated August 14, 2013 in Docket No. 13-01-19, pp. 126, 146 and 147. In reaching this determination, the Authority reviewed the language of the decoupling statute, the Company's proposal, the positions of the parties and past Authority Decisions addressing decoupling. The Authority finds that the decoupling rate will be a single, company-wide rate per kWh. The Authority also finds that the Company's proposal to include all sources of revenue in the decoupling calculation is appropriate. The Authority does not approve CL&P's proposal to assign carrying charges to either an over- or under-recovery or to any deferral. The Authority further directs that the present CIAC practices remain the same without any of CL&P's alterations. Additionally, as detailed in Section II.F.4 above, the 15 basis points reduction to the Company's for the Rate Year will reduce the revenue requirement and be reflected in an adjustment to the allowed revenue requirement target in the Company's first decoupling mechanism reconciliation. In following years, the Company may true-up to its full allowed revenue requirements. The Authority directs the Company to include the adjustment for the ROE penalty in its Rate Year decoupling mechanism reconciliation filing.

The OCC, AG and BETP expressed in their Written Exceptions their concern with including the adjustment for the ROE penalty in the decoupling reconciliation, and recommended that Rate Year rates be reduced immediately to reflect the penalty. OCC Written Exceptions, pp. 15-17, AG Written Exceptions, p. 4-6, BETP Written Exceptions, p. 2. They indicated this rate treatment means that customers may not see the full benefit of this reduction for two and a half years or more. This was not the Authority's intent. As discussed in the June 27, 2014 letter issued by the Authority and the Prehearing Conference held on June 19, 2014, it was agreed upon by the parties that the effective date of new rates will occur after the effective date of the Rate Year, which begins December 1, 2014. Similar to its directive for the ROE penalty, the Authority is not requiring the Company to design rates that reflect the delayed implementation of rates. Therefore, the Authority anticipates a shortfall in Rate Year revenue due to the delayed implementation of rates. In other words, customers are realizing the benefit of the penalty immediately by a delay in the implementation of rates rather than over the course of the Rate Year.

The decoupling statute, Conn. Gen. Stat. §16-19tt, provides in relevant part:

> (b) In any rate case initiated on or after July 8, 2013, or in a pending rate case for which a final decision has not been issued prior to July 8, 2013, the Public Utilities Regulatory Authority shall order the state's gas and electric distribution companies to decouple distribution revenues from the volume of natural gas and electricity sales. For electric distribution companies, the decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues . . . . In making its determination on this matter, the authority shall consider the impact of decoupling on the gas or electric distribution company's return on equity and make any necessary adjustments thereto.

With respect to the electric decoupling, the legislature expressed its intent to specifically require one type of mechanism with language clearly stating that the "decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues."

In the Application, the Company originally proposed a decoupling methodology that would reconcile actual revenues to PURA-approved revenues. At the end of each Rate Year, the Company would calculate the annual difference in revenues and establish a single kWh rate applicable to all customers over the following year. In addition, carrying charges[37] and a prior-year decoupling true-up will apply. The Company proposed to retain the revenue collected from post-rate year customers requiring a service set[38] (new service customers). The Company claimed that this money is needed to compensate them for the cost of installing new equipment. Absent retention of new service customer revenues, the Company suggested that new service customers be charged a 100% CIAC grossed up for income taxes. The annual process will continue until the Company's next rate application where PURA-approved revenues will be reset. Goodwin PFT, pp. 9-11.

During the hearing, the Company revised its decoupling proposal. Under the revised proposal the Company would add revenues received from post-rate year new service customers to the allowed revenues established in the instant case. The original proposal subtracted new service customer revenues from actual revenues. The decoupling amount is identical in either case. According to the Company, the new approach satisfies the language of the statute[39] because the Authority has great latitude in determining allowed revenues. Further, the Company argued that:

> In addition, there are other statutory provisions that relate to CL&P's statutory right to recover revenues lost due to various Connecticut policy initiatives regarding renewable energy and collectively ensure that the

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37 The carrying charge as proposed will equal the Company's overall cost of capital.

38 Service set customers are new customers lacking any electrical service at their location. The Company will need to install a meter, service and possibly extend the distribution system as well to service these customers.

39 Conn. Gen. Stat. §16-19tt(b) defines decoupling for electric companies as follows: "For electric distribution companies, the decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues."

> Company can recover the revenues due to it as a result of PURA rate rulings (provided below). Collectively, these provisions establish that the Company has a right to recover revenues that are lost due to initiatives such as energy efficiency and the waiver of back-up charges for DG[40] customers, which is recovery obtained through the NBFMCC[41] rate. Other programs resulting in lost revenue (going forward after rates are set in this case), such as virtual net metering will be recovered in future NBFMCC rate filings.
>
> Late Filed Exhibit No. 15.

The Company reiterated the PURA's right to establish allowed revenues in its preliminary brief and also argued that the decoupling statute must be read in concert with the Authority's responsibility to establish just and reasonable rates.

> In regard to §16-19tt, the legislative directive to implement a revenue decoupling mechanism for CL&P cannot be read in isolation, but rather it must be read within the context of, and consistent with, PURA's full rate-making authority as set forth in §§16-19, 16-19e(a) and related sections. PURA cannot implement decoupling in a manner that would cause CL&P's rates to be less than just and reasonable, or insufficient to cover its operating costs. Conn. Gen. Stat. §16-19e(a)(4). Therefore, the Authority has broad discretion to establish "allowed revenue" for purposes of the decoupling tariff to equal the revenues associated with the revenue requirement approved in this case for the rate year, plus the distribution revenues collected from new customer connections after the rate year. Absent the inclusion of the new customer revenue as part of allowed revenue, the decoupling mechanism would result in the Company incurring incremental capital investment and cost of service associated with the new customers, with no means of recovering or offsetting these costs short of filing a new rate case.
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> CL&P Preliminary Brief, pp. 7 and 8.

Other parties to the docket presented their positions regarding CL&P's decoupling proposal. The CIEC wants all large C&I and DG customers to be exempt from the proposed company-wide decoupling rate. Absent full exemption, the CIEC recommended a decoupling rate that is equally applicable to all rate classes on a company-wide rate per kWh basis. CIEC Brief, pp. 22-24. The AG requests that the Authority reject the Company's proposed decoupling methodology because it lacks the fundamental symmetry contemplated by the decoupling statute and the Company's proposal to retain revenues from new service customers is not permitted by decoupling statute. AG Brief, pp. 21, 22 and 23.

The Bureau of Energy and Technology Policy (BETP) supported the Company's proposal. The Company should be allowed to retain new service customer revenues because it is only a minor adjustment that may help delay the need for a new rate case.

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[40] Distributed generation (DG).

[41] Non-bypassable Federally Mandated Congestion Charge

BETP also considered decoupling to be an effective cost-recovery alternative to increasing fixed charges as proposed by the Company. BETP Brief p. 13; Reply Brief, p. 1.

Environment Northeast (ENE) favors granting the Company full revenue decoupling because it will not hamper state energy policy and can be used to replace the need for fixed charges. ENE defines decoupling as actual revenue coming in less than allowed revenues. ENE Brief, p. 8.

Wal-Mart[42] argued that since demand-metered customers are already paying substantially excessive rates, no decoupling charge should apply. Additionally, a company-wide kWh decoupling charge as proposed by the Company only introduces further inter-class subsidization. For rate classes that have no volumetric kWh rates, a kWh decoupling charge also shifts cost responsibility from lower load factor customers to higher load factor customers. Wal-Mart Brief, pp. 4-6.

The OCC disagreed with the Company's position in three respects. First, it recommended that decoupling be applied at either the individual rate class level or at a broader residential, commercial and industrial level. Use of broader levels would prevent potentially severe impacts in customer classes with relatively few customers. Second, whereas the Company proposed to include carrying charges equal to its weighted average cost of capital, the OCC argued that CL&P's short-term cost of debt is more appropriate. Finally, the Company's proposal to adjust either allowed or billed revenues to remove revenues from new service customers is outside the scope of the legislation and should be denied by the Authority. OCC Brief, pp. 138-142. In response to the CIEC's argument that larger rate classes should be exempt from decoupling because they are already decoupled through rate design, the OCC stated that a reduction in their demand levels, for example, would be trued-up by other rate classes. Further, the OCC disagreed with the BETP's claim that the Company should be allowed to retain new service customer revenues. The OCC pointed out that retained revenues include all customer, energy and demand charges that exceed the cost of newly installed facilities. OCC Reply Brief, pp. 22-25.

The Authority finds that CL&P's proposed decoupling mechanism is not permissible, based on the plain and express language of the decoupling statute. The decoupling statute requires the adjustment or reconciliation be made on the basis of a true up between allowed distribution revenues and "actual distribution revenues." The statute makes no provision for the exclusion of any revenue, such as new customer revenue, from the revenue reconciliation. The Authority, therefore, declines to interpret that statute, as CL&P urges, to conclude that certain actual new customer revenues should be excluded from the decoupling true up adjustment or treated as an upward adjustment to allowed distribution revenue.

Besides not being permitted by the plain and express statutory language, the Authority also finds that CL&P's proposal is contrary to the legislative intent of the decoupling statute to establish a balance and symmetry between the electric or gas

[42] Wal-Mart Stores East, LP and Sam's East are intervenors collectively referred to as Wal-Mart.

distribution companies and their customers.[43] In its Decision dated January 22, 2014 in Docket No. 13-06-08, the Authority described the legislative intent for:

> . . . decoupling to be a simple true-up mechanism established to decouple revenue from fluctuations in sales. If utility rates reflected only fixed monthly charges, then fluctuations in revenue would parallel customer count. As expressed to the PURA by Connecticut utilities many times in numerous dockets, decoupling only permits the utility to recover its revenue requirement calculated by the Authority as the amount just adequate to provide safe, reliable service, no more, no less. Decoupling is symmetrical in theory in that it requires ratepayers to contribute missing revenues to utilities and in turn, for utilities to refund additional revenues to ratepayers. In practice, however, decoupling can favor ratepayers or utilities over extended periods. For example, in a warming world of expanding customer conservation coupled with poor economic activity, utilities will collect more from ratepayers than they refund. Alternatively, in a situation of unprecedented customer growth, ratepayers would be expected to share in the financial benefits.
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> Docket No. 13-06-18 Decision, p. 122.

The Company's legal argument submitted in support of its latest proposal to adjust allowed revenues, centers on the Authority's need to read the decoupling statute in concert with its responsibility to approve nothing less than just and reasonable rates. The Authority is aware of those requirements. Decoupling is not a rate developed to recover underlying, prudently incurred costs. It is a true-up mechanism for revenues previously designed fully in accordance with the Authority's just and reasonableness responsibility. Adding future unknown costs to today's allowed revenues to incorporate a single item of cost, even if it is described by some as minor, it is another version of single-issue rate-making that violates the symmetrical balance of decoupling. Therefore, the Authority rejects the Company's decoupling proposal. The Company will be directed to revise its proposed Decoupling Rates Rider to reflect the formula approved for UI. That formula is consistent with the enabling legislation and was implemented for all other utilities granted decoupling to date. If at any time in the future, CL&P determines that decoupling and other approved rate mechanisms are insufficient for the Company to collect enough revenue to provide adequate and reliable electric service at just and reasonable rates, recover its costs, and give CL&P a reasonable opportunity to earn a reasonable return, the Company may file a rate case application seeking an increase to its allowed distribution revenues and other rate relief.

The Authority has determined that present CIAC practices will not to be altered. While it is true that new service customer revenues will be returned to ratepayers, a new customer has no control over the situation and should not provide the Company with a contribution newly calculated outside of existing practices. Since new service

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[43] In this proceeding, the Company's witness also acknowledged that the decoupling relationship is intended to be symmetrical, with risks and potential benefits for both the Company's shareholders and its ratepayers as stated below. Tr. 9/3/14, pp. 955 and 956.

subscribers tend to be customers for many years, valuing their contribution to costs must be normalized over the life of the analysis. Imputing zero revenues for a few years of a 50-year revenue contribution stream is inappropriate. The potential loss of revenue from new service customers is more than balanced from the protection ratepayers stand ready to provide should sales decrease for any reason.

The Authority finds that the decoupling rate will be a single, company-wide rate per kWh. Customers serviced by rate classes lacking volumetric distribution rates should be charged the same rate based on their monthly kWh usage. The Authority understands the OCC's concern that a single, company-wide decoupling rate inevitably involves inter-class subsidizations that are always inappropriate when viewed from the perspective of any single class. Nonetheless, decoupling is only a true-up mechanism that involves minimal dollars in comparison to total distribution revenues. Individual customers are involved in this true-up; but only to the extent of their relative level of annual consumption. Small consumption customers are charged or benefitted less than large consumption customers. Decoupling at either the rate class or broader group level introduces the possibility of simultaneous debit and credit charges within the same true-up year. Ultimately, decoupling is a blunt regulatory or administrative tool utilized until the rate formula can be rebalanced in a future rate case. Decoupling will supersede the existing conservation adjustment mechanism (CAM) and lost revenue true-ups within the FMCC reconciliation process. The Company will be directed to propose a phase-out formula at its next scheduled CAM and Federally Mandated Congestion Charge reconciliation filings.

The Authority finds that the Company's proposal to include all sources of revenue in the decoupling calculation is appropriate. A regulatory asset (debit or credit) will be created following Authority approval of the Company's annual decoupling calculation. The asset will be written off monthly using actual billings. The last month's write-off will use actual billed revenues and estimated net unbilled revenues for the year. Since allowed revenues will not change during the year, all accounting and financial reporting documents prepared for public consumption will reflect a forecast of normalized allowed revenues for the period in question. Customer bills will present the decoupling charge on a separate line item entitled Revenue Adjustment Mechanism per kWh. Annual requests to the Authority for approval of a new decoupling rate may follow the format recently employed by UI. Annual decoupling filings should be made expeditiously following the availability of complete data. The actual rate calculation will use forecasted sales for the upcoming collection year. The decoupling rate will not be grossed-up for gross receipt tax or uncollectible expense. Periodic decoupling audits will be conducted by the Authority.

I. EARNINGS SHARING MECHANISM

An earnings sharing mechanism (ESM) is a ratemaking mechanism that shares a company's earnings in excess of its allowed ROE. The purpose of an ESM is to provide for the equitable distribution of a company's earnings above its allowed ROE between the company's customers and shareholders. Typically, the Authority has established the sharing threshold at the Company's allowed ROE with the sharing distributed equally with 50% to shareholders and 50% for the customers. Since 1999, the

Company has operated under an ESM whereby earnings in excess of the allowed ROE are shared with ratepayers.

Connecticut's over-earnings statute, Conn. Gen. Stat. §16-19(g), allows the Authority to review a company's earnings if an earned ROE exceeds a company's authorized ROE by 1% point for a period of six consecutive months, equivalently two fiscal quarters. The Authority has a long tradition of using an ESM and has approved these for companies as an incentive to shareholders. Its implementation allows shareholders to capture a portion of potential overearnings and also avoiding an overearnings financial review that would be otherwise initiated by the Authority. The ESMs have been implemented in the past for electric, gas and water utilities.

In this proceeding, CL&P is proposing a change to the existing ESM by suggesting a 100-basis point deadband above its authorized ROE, within which, there would be no sharing. Between 100 and 150 basis points above the allowed ROE, earnings would be shifted with 75% shareholders and 25% shared to ratepayers. For earnings above 150 basis points, CL&P offers to share earnings equally. According to the Company, the proposed ESM may help mitigate CL&P's exposure to the downside risk of earnings deficiencies. CL&P claims that if it could retain a higher margin of earnings, it would provide a strong incentive for the Company to undertake broad-scale efficiency measures that would consume management focus, institutional resources and, in some cases, costs to achieve, but would reduce the cost of service for customers in the next rate case. Hevert PFT, pp. 42–47.

A recommendation to reject CL&P's proposed changes to the ESM was also provided by Wal-Mart. Per traditional regulatory practice, the Company has the opportunity, but not the guarantee to earn its authorized return. Chriss PFT, p. 14. According to Mr. Chriss, over-earnings indicate that rates are set too high and should be reduced. Implementation of the proposed deadband above the allowed ROE results in the potential for the Company to significantly over-earn with no offset to customers of the rates that have been set too high. Chriss PFT, p. 15. Mr. Chriss stated that the current ESM already provides an incentive for the Company to maximize the efficiency of its operations, as achieved cost reductions that increase earnings over the authorized return are awarded with 50% of the over-earnings going to the Company. Id. Mr. Chriss also claims that the Company has not provided sufficient justification to deviate from the precedent established by PURA with respect to ESMs. Wal-Mart Brief, p. 8.

Additionally, the CIEC stated that the Company's proposal would significantly reduce the ability of ratepayers to share in over-earnings without providing any additional corresponding benefit. CIEC Brief, p. 29. The CIEC concurs with Mr. Chriss that CL&P is not entitled to nor guaranteed to over-earn its rate of return. Id. Contrary to the Company's assertions, the record in this proceeding demonstrates that the current ESM already provides sufficient incentive to maximize the efficiency of its operations. CIEC Brief, p. 30. The AG also recommends that CL&P's proposed ESM be rejected as unfair to ratepayers. AG Brief, p. 11. Since the Company can expect to see increasing earnings and savings resulting from efficiencies created by the merger between NU and NSTAR, the AG claimed that CL&P's proposed ESM would funnel the vast bulk of those savings back to its shareholders. Id.

The Authority finds that CL&P's current ESM provides sufficient incentive to maximize the efficiency of its operations as the Company is rewarded for its efforts with 50% of any earnings above its authorized ROE. Under the existing ESM, the Company has achieved efficiencies associated with the merger with savings in operating expenses and by optimization of its facilities. The Authority expects the Company to continue to strive for efficiencies in its operations. The current ESM is also consistent with other recent ESMs that were approved by the Authority for electric, gas and water utilities. The Company should maintain an equal share of the benefits and savings and continue to pursue efficiency in all areas of its operations. The Authority directs CL&P to continue its existing ESM. The earnings sharing mechanism shall remain in effect until the Company's next rate case where it will again be reviewed. Accordingly, the Company's excess earnings over its allowed ROE of 9.02%, or 9.17% in 2016 and beyond, calculated using the cost of capital method will be shared 50/50 ratepayers/Company. The ratepayers' share of any such excess earnings will be returned through a line item credit on their bills.

J. RATES, REVENUE AND TARIFFS

1. Sales Forecast

CL&P stated that historically, electric rates have generally followed the economy, and the relationship is critical to understanding and forecasting electric use. The level of economic activity is a driver in determining customers' purchase and operation of electric equipment and appliances that subsequently determine electric demand. Residential customers are determined by the number of households, and residential electric sales are correlated with household income. Commercial sales are driven by growth in the non-manufacturing sector, which also provides jobs that produce additional residential sales growth. Industrial sales are driven by manufacturing employment and productivity. For this reason, a sales forecast is generally a reflection of the underlying economic forecast. The economic forecast used by CL&P in this case was developed by Moody's Economy.com in July 2013. Plecs PFT, pp. 1 and 2.

While the recession had a dramatic impact on sales, CL&P indicated a recovery seems to be underway and its economic forecast predicts that this modest recovery is expected to continue throughout the forecast period. In 2011 and 2012, total retail sales declined by 0.5% and 0.2%, respectively, on a weather-normalized basis. However, 2013 proved to be a turning point, with sales up 0.7% over 2012. Residential sales growth has been flat to positive, accelerating during the most recent years of the economic recovery. Commercial sales only recently turned positive in 2013, and industrial sales growth has been volatile, growing in 2012 before a sharp decline in 2013. While the economic recovery has been volatile for several years, it now appears to be gaining some momentum in some sectors, with some degree of stability in non-manufacturing employment and household incomes. The Company nevertheless expects that the industrial sector will continue to be volatile and difficult to predict. Id.

CL&P forecasts retail sales to remain relatively flat through 2016. Forecasted CL&P retail sales are shown in the chart below:

Table 66

Exhibit CAP-7 CONNECTICUT LIGHT AND POWER COMPANY- TOTAL FRANCHISE SALES CALENDAR ELECTRIC SALES GIGAWATT HOURS											
	RES.		COM.		IND.		ST. LIGHT.		RAIL-ROAD		TOTAL RETAIL
	SALES	% CH	SALES	% CH	SALES	% CH	SALES	% CH	SALES	% CH	SALES
FORECAST											
2014	10,295	1.1%	9,525	0.9%	2,290	-1.0%	96	-1.3%	194	2.3%	22,401
2015	10,307	0.1%	9,514	-0.1%	2,285	-0.2%	95	-1.0%	196	0.9%	22,397
2016	10,387	0.8%	9,528	0.2%	2,267	-0.8%	94	-1.0%	198	0.9%	22,474

Application, Exhibit CAP-7.

The resulting flat sales forecast reflects both an anticipated modest improvement in economic conditions in certain sectors, and it includes the effect of expanded Company-sponsored energy efficiency programs, which are expected to add approximately 300 gigawatt hours (GWh), or nearly 1.5% of annual sales, of new energy efficiency measures per year. The forecast is structured to consider previously installed measures, which still provide an energy savings benefit, and the estimated impacts of future programs, without double-counting those savings with the savings implied by the regression model's historical relationships.

Historically, the Company's sales have very closely mirrored economic activity. In the last 10 years, that relationship held subject to adjustments for energy price spikes and DG activity. The Company stated it expects that this sales-economy relationship to hold through the forecast period, subject to additional adjustments for growth in DG and energy efficiency programs. However, CL&P cautioned that a number of factors may affect the sales outlook such as weather, economic activity, energy prices, energy efficiency, and DG activity. Plec PFT, pp. 3-8.

a. Forecasting Methodology

i. Trend Forecast

CL&P traditionally used statistically adjusted end-use models to forecast sales by customer class, which were useful in identifying the end-use factors that are driving energy use. For the purposes of the instant case, CL&P changed its sales forecasting methodology to a traditional econometric, or trend, model to forecast customer and sales for the Rate Year. The Company found that both approaches produce similarly reliable results. It decided to use the econometric modeling approach because it produces reliable results with less complexity at lower cost. CL&P Response to Interrogatory OCC-204. The Company forecasted sales on the customer class level, (e.g., Residential, Commercial, Industrial, Street Lighting and Railroad). Late Filed Exhibit No. 16, Attachment 1; Tr. 9/3/14, pp. 825-827. The Company indicated it performed a weather normalization study in developing the rate year sales forecast and associated revenues. CL&P Response to Interrogatory OCC-123.

The Company also provided its lost sales associated with the major recent weather events. CL&P lost approximately 159 GWh in 2011, or 2.2% of its sales for the affected period, due to Hurricane Irene and the October 2011 snowstorm. In 2012, CL&P lost approximately 86 GWh, or 2.6% of its sales for the affected period, due to Hurricane Sandy. Late Filed Exhibit No. 16, Attachment 2. The Company adjusted the forecast models' dataset historical for the impact of these storms by using a separate set of weather-specific sales models to capture the sales impacts of both statistically significant weather events and the typical variations caused by heating and cooling degree days. In some cases where a storm is substantial, it used a binary variable to account for some unusual relationships between the economic driver and the actual sales experience to make sure that that relationship was not something that the model would interpret as a normal response. Late Filed Exhibit No. 16; Tr. 9/3/14, pp. 828 and 829.

ii. Out of Model Adjustments

The Company made a series of “out of model” adjustments to the trend forecast to adjust sales where new demand side programs are in place and/or it finds the trend forecast is not accurately capturing a particular sales trend. For instance, the Company increased its C&LM spending, and expects to lose additional sales that are not reflected in historical sales trend which only include the base conservation savings. Other items that the Company adjusted for are distributed generation, the residential solar program, electric vehicle program, the low- and zero-emission renewable energy credit (LREC/ZREC) program and large customer changes. The Company provided a summary of the out of model adjustment:

Table 67

CL&P Out of Model Adjustments									
GWH									
	Residential Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	Residential Solar Program	Electric Vehicles	**Total Out of Model Adjustments**	Final Forecast	
2014	10,306	-10	-5	0	-10	14	**-11**	10,295	
2015	10,355	-36	-12	0	-20	21	**-47**	10,307	
2016	10,446	-61	-19	21	-30	30	**-59**	10,387	
	Commercial Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	2008 DG Program	Large Customer Changes	**Total Out of Model Adjustments**	Final Forecast	
2014	9,863	-7	-70	0	-280	19	**-338**	9,525	
2015	9,921	-25	-168	0	-284	69	**-407**	9,514	
2016	9,998	-43	-268	24	-285	102	**-470**	9,528	
	Industrial Adjustments								
Year	Eviews Trend Forecast	Energy Efficiency	LREC/ZREC Program	Leap Year	2008 DG Program	Large Customer Changes	Large Customer Self-Generation Unit	**Total Out of Model Adjustments**	Final Forecast
2014	2,778	-2	-19	0	-385	19	-102	**-488**	2,290
2015	2,785	-7	-46	0	-385	39	-102	**-500**	2,285
2016	2,794	-11	-73	6	-385	39	-102	**-527**	2,267

Late Filed Exhibit No. 8.

iii. Rate Class Sales Allocation

Once the sales forecast was developed at the customer class level, the Company looked at the test year billing data from its records, specifically the relationships based on the customer class versus rate class sales levels. In developing the rate class level forecasts, CL&P then used those relationships to extrapolate the customer, demand, and sales billing determinants. CL&P utilized the relationships of customer class to rate class sales in the test year to develop the rate year comparable billing units by rate class. Tr. 9/3/14, p. 832.

b. Sales Forecast Results

The table below summarizes CL&P's proposed Rate Year rate revenue at present rates and the forecasted changes in customer, sales and revenues from the Test Year, allocated among each of the rate classes:

Table 68

		Test Year revenues at current rates				Rate Year revenues at current rates				% Change		
Rate	Schedule/Description	Average Number Of Customer Bills Rendered	Weather Normalized Sales (mWh)	Average Current Rates (cents/kWh)	Base Revenue ($000)	Average Number Of Customer Bills Rendered	2015 Forecasted Sales (mWh)	Average Current Rates (cents/kWh)	Base Revenue ($000)	Customers	Sales	Revenue
1	Residential - Regular	969,421	8,331,016	18.40	$ 1,532,836	984,231	8,461,362	18.40	$ 1,556,750	1.53%	1.56%	1.56%
5	Residential - Electric Heat	138,749	1,828,279	17.61	$ 321,999	138,749	1,828,279	17.61	$ 321,999	0.00%	0.00%	0.00%
7	Residential - Time-Of-Day	486	6,066	17.40	$ 1,055	493	6,156	17.40	$ 1,071	1.53%	1.48%	1.48%
18	Controlled Water Heating *	196	878	16.74	$ 147	196	878	16.74	$ 147	0.00%	0.00%	0.00%
27	Time-Of-Day (TOD) General	74	13,934	18.85	$ 2,626	74	13,961	18.85	$ 2,632	0.81%	0.20%	0.20%
29	Outdoor Lighting	205	3,211	23.96	$ 769	208	3,232	23.99	$ 775	1.58%	0.64%	0.79%
30	Small General	97,793	3,257,931	18.20	$ 593,030	99,250	3,275,128	18.22	$ 596,593	1.49%	0.53%	0.60%
35	Intermediate General	3,053	1,142,788	15.64	$ 178,739	3,095	1,148,500	15.65	$ 179,744	1.37%	0.50%	0.56%
37	Intermediate TOD	1,514	1,282,415	15.24	$ 195,426	1,528	1,285,729	15.24	$ 195,975	0.96%	0.26%	0.28%
39	Interruptible Menu	8	235,489	9.78	$ 23,020	8	235,489	9.78	$ 23,020	0.00%	0.00%	0.00%
40	Church and School	2,116	115,402	17.51	$ 20,212	2,116	115,402	17.51	$ 20,212	0.00%	0.00%	0.00%
41	Large Church and School	16	15,096	17.09	$ 2,579	16	15,096	17.09	$ 2,579	0.00%	0.00%	0.00%
55	Intermediate TOD Manufacturers	320	681,030	12.56	$ 85,569	317	674,097	12.56	$ 84,700	-0.86%	-1.02%	-1.02%
56	Intermediate TOD Non-Manufact	955	2,021,971	12.99	$ 262,678	968	2,032,033	12.99	$ 264,026	1.35%	0.50%	0.51%
57	Large TOD Manufacturers	139	1,095,288	11.68	$ 127,927	136	1,077,844	11.68	$ 125,898	-1.58%	-1.59%	-1.59%
58	Large TOD Non-Manufacturers	205	2,036,690	12.20	$ 248,407	208	2,052,918	12.20	$ 250,402	1.21%	0.80%	0.80%
115	Unmetered	2,633	53,500	16.49	$ 8,820	2,652	53,500	16.49	$ 8,820	0.71%	0.00%	0.00%
116	Street & Security Lighting	2,349	92,563	26.41	$ 24,445	2,349	92,563	26.41	$ 24,445	0.00%	0.00%	0.00%
117	Partial Street Lighting Service	333	23,425	14.43	$ 3,380	333	23,425	14.43	$ 3,380	0.00%	0.00%	0.00%
119	Special Contracts	3	1,320	37.31	$ 492	3	1,320	37.31	$ 492	0.00%	0.00%	0.00%
	Total	1,220,369	22,238,292	16.34	$ 3,634,158	1,236,734	22,396,911	16.36	$ 3,663,662	1.34%	0.71%	0.81%

Exhibit EAD-14, pp. 1 and 2.

c. Position of the Parties

None of the Parties commented on CL&P's proposed sales forecasting methodology or the forecast results in their respective testimony or Briefs.

d. Authority Analysis

The Company is forecasting customer growth of approximately 1.2% for the residential, 1.4% for the commercial and 0.4% for the street lighting customer classes over test year levels, and a decrease in customer growth in the industrial class of 1.2%. CL&P Responses to Interrogatories OCC-304 and OCC-305. The Authority reviewed CL&P's forecasting methodology and forecasting results and finds the methodology reasonable and the results acceptable for setting rates. The sales numbers for 2015 reflect a modest level of growth in sales, consistent with observed and forecasted economic trends, known customer changes, and offset by expected sales reductions due to various demand-side program initiatives. The customer forecast is also reasonable given historic trends and expected changes, as discussed in the case.

2. Operating Revenue

CL&P filed the following summary of earned operating revenues for the Test Year, forecasted Revenue at present rates using the sales forecast discussed in Section II.J.1, Sales Forecast, proposed Rate Year revenues based on the rate request, and the associated revenue increase.

Table 69

DISTRIBUTION COSTS

OPERATING INCOME SUMMARY - RATE YEAR ENDING 2015

Description	Rate Year Ending 2015 at Current Rates	Required Increase		GET & Uncollectible Adjustment	Required Increase including GET & Uncollectible	Rate Year Ending 2015 at Proposed Rates
Operating revenues (distibution only)	$ 905,882	$ 108,101	(a)	$ 8,607	$ 116,708	$ 1,022,590
Operating revenues (storm cost)	$ -	$ 82,928	(a)	$ 6,603	$ 89,531	$ 89,531
Operating revenues	$ -	$ 23,474	(a)	$ 1,869	$ 25,343	$ 25,343
	905,882	$ 214,503		$ 17,079	$ 231,582	$ 1,137,464

Application, Schedule C-1.0.

CL&P's proposed Rate Year revenue at present rates of $905.882 million consists of $883.661 million of rate revenue based on applying CL&P's current distribution rates to forecasted sales volumes and $22.221 million in "other" revenues. Application, Schedule C-3.1.

a. Rate Revenue at Present Rates

Based on the sales forecast discussed in Section II.J.1, Sales Forecast, CL&P calculated Rate Year distribution revenue at present rates of $883.667 million.[44] Since the Authority accepted the Company's sales forecast, no change to the rate revenue at present rates is needed.

b. Other Revenues

CL&P forecasted an increase in "other" operating revenues from $22.038 million in the Test Year to $22.221 million in the Rate Year, a total increase of approximately $183,000. The Company showed that this is primarily due to an expected increase in revenue related to increasing the pole attachment rental rates. Schedule WPC-3.1. The following table illustrates the breakdown of Rate Year other revenues.

[44] There is a slight discrepancy of $6,000 in CL&P's distribution revenue at present rates shown in the C-Schedules vs. the E-Schedules.

Table 70

OTHER REVENUES - RATE YEAR ENDING 2015		
Amounts in $000's		
Account	**Description**	**Amount**
450.01	Late Payment Charge	$ 6,994
450.04	Other Late Payment Charge	2,371
	Forfeited Discounts	$ 9,365
451.01	Reconnect Fees	$ 734
451.02	Return Check Charges	328
	Misc. Service Revenues	$ 1,062
454.01	Intercompany Rent/Lease	$ 104
454.99	Rent from Elec Property (Other)	10,912
456.51	Other Facilities Charge Revenue	41
456.99	Other Electric Revenue	737
	Rent From Electric Property	$ 11,794
	Total Rate Year	$ 22,221

Response to Interrogatory RA-11, Attachment 1.

i. Late Payment Charge / Reconnection Fee Revenue

Late payment charge revenue is generated by the Company by charging 1% on a customer's delinquent balance. Revenue from reconnect fees consists of two charges: a reconnect at meter charge of $35 and a reconnect at pole charge of $60. These service charges are listed in Appendix A of the Terms and Conditions for Delivery Service, and have been in effect throughout the period 2008-2013.

Table 71

The Connecticut Light and Power Company Annual Company Revenue for Late Payment Charges and Reconnection Fees (Amounts in Dollars)						
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
1.) Late Payment Charges (a/c 450)	7,713,350	8,908,561	9,590,315	6,097,963	8,269,604	9,365,076
2.) Reconnect Fees (a/c 451)	334,530	763,935	1,757,841	1,033,975	1,081,085	734,182
Total	8,047,880	9,672,496	11,348,156	7,131,938	9,350,689	10,099,258

Response to Interrogatory RA-10.

The Authority finds the proposed revenues associated with late payment charges to be reasonable. However, the rate year revenues for reconnect fees for 2013 are low compared to prior years, and should not be used as the basis for forecasting Rate Year revenue. The five-year average of reconnection revenue shown in the table above based on current charges is $1,074,204. As noted in Section II.J.8, Tariff Changes, the Authority is requiring that CL&P increase the charge for reconnection at the meter from

$35 to $42, a 20% increase, instead of the Company's proposal to lower the charge to $31. The Company is also proposing to increase the charges substantially for reconnections at the pole, by more than 100%. The Authority will adjust the Company's proposed revenue for reconnection fees to $1,350,000, which reflects the 5-year average through 2013 and approximately 25% in additional revenue expected from the increase in the reconnection charges. Therefore, other revenues will be increased by $615,818 as a result of the adjustment to reconnect fees.

ii. Pole Attachment Revenue

The OCC recommended that the Authority impute $275,260 of revenue to CL&P's Rate Year related to amount of annual pole attachment revenue it contends CL&P should receive from Verizon in the portion of Greenwich where CL&P and Verizon are joint pole owners. The OCC's recommendation is based on the following:

- CL&P has an agreement with Verizon that gives all recurring attachment revenues for jointly owned poles to Verizon.

- With ratepayer funding, CL&P pays for its share of the capital costs for all poles it jointly owns with Verizon. CL&P is also the custodian of more than 60% of the poles that it jointly owns with Verizon, and CL&P pays for O&M associated with its designated custodial poles.

- CL&P receives none of the revenue collected from attachers in the communications gain on the poles it owns jointly with Verizon.

Consequently, the OCC argued that because ratepayers share capital and custodial costs, they should share in the revenue associated with their jointly owned poles. Response to Interrogatory OCC-360; OCC Brief, pp. 109-111.

CL&P indicated that the 1956 contract between CL&P and Verizon's predecessor (the New York Telephone Company), which pre-dates the existence of cable television and fiber pole attachments, does not allow CL&P to retain any of the revenues from such attachments in the communications gain space on jointly owned poles. Responses to Interrogatories OCC-209 and OCC-360. Therefore, CL&P currently has no legal entitlement or mechanism through which to recover it from Verizon. CL&P Reply Brief, pp. 61 and 62.

The OCC also recommended that the Authority impute $1.946 million into Rate Year revenue, which reflects the amount of make-ready expense CL&P incurred in the test year that it did not recover from pole attachers. The OCC's recommendation for cost recovery is based on the following:

1. The communications gain on the pole is used by telecom/cable attachers for their service provision.

2. Code compliance work in the communications gain is necessitated by having the attachers' equipment in the communications gain. The attachers are the beneficiaries and the cost causers of the code compliance work.

3. While Telecom/cable companies should be allowed to attach to utility poles, the OCC is unaware of any statutory or regulatory requirement that electric ratepayers must subsidize their attachment.

4. CL&P should be made whole for make-ready costs by the attachers, who are the cost causers, not by the CL&P ratepayers.

For the future, the OCC recommended that the Authority direct the Company to develop a recurring or non-recurring rate for the attachers that provides the revenues necessary to reimburse CL&P fully for the cost of make-ready work in the communications gain. OCC Brief, pp. 111 and 112.

CL&P indicated that it does not have explicit permission from the Authority to recover these specific make-ready costs from pole attachers. CL&P agreed with the OCC's statements that "the OCC is unaware of any statutory or regulatory requirement that electric ratepayers must subsidize their attachment" and "CL&P should be made whole for make-ready costs by the attachers." However, the OCC's proposed increase to CL&P's rate year revenues cannot be made unless CL&P receives permission from the Authority in this case to recover this specific type of make-ready expense from pole attachers. Reply Brief, pp. 62.

The Authority will not impute revenue associated with the poles that it jointly owns with Verizon. Although CL&P is responsible for some O&M on these joint poles without full compensation, it is limited in nature to inspection and fixing damage arising from outside sources. It is unclear what the costs associated with the O&M activities are and what the real revenue deficiency is. In any event, it appears in either case that CL&P has no legal means at this time to collect revenue from Verizon under the Agreement. Imputing a revenue estimate into rates would serve to penalize the Company. The Authority finds CL&P's actions here do not warrant the penalty proposed by the OCC. The Authority will require CL&P to address this issue in the pole attachment working group meetings ordered pursuant to the October 8, 2014 Decision in Docket No. 11-03-07, DPUC Investigation into the Appointment of a Third Party Statewide Utility Telephone Pole Administrator for the State of Connecticut. The Company will be directed to report back to the Authority with a proposal that addresses the OCC's concerns.

The Authority also finds that the Company is billing properly for make-ready work under existing Authority guidelines and, therefore, will not impute revenue associated with make-ready revenue shortfalls proposed by the OCC. Not all make-ready costs are the responsibility of the attacher, such as when a new attachment is requested and the electric distribution company finds in its survey that there is a national electric safety code violation and takes corrective action.

As discussed in Section II.J.6, Pole Attachment Rates, the Authority lowered CL&Ps proposed CATV Rate from $16.56 to $13.19 and the proposed Telecom Rates were lowered from $16.56 to $13.82 and $13.89 for urban and rural attachments, respectively. The Authority could not calculate the resultant adjustment to Rent from Electric Property, Account No. 45499, as the billing determinants for pole attachments is not available. Since the adjustment will decrease Other Revenues, the Company shall include the adjustment in distribution revenue when designing rates.

c. Summary of Changes

Based on the adjustments made to other revenue herein, the initial change to Rate Year revenue will be an increase of $615,818. This increase will be offset by the reduction in in pole attachment revenue discussed in Section II.J.2.b, Pole Attachment Revenue.

3. Cost of Service Study

In general, a cost of service study (COSS) is a mathematical business model that systematically assigns cost responsibility among customer classes for company assets and expenses incurred by an EDC to serve customers. Since the COSS culminates in summarizing customer, demand and total costs by customer class, it is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class. In developing its COSS, the Company followed the detailed methodology consistently approved by the Authority in recent rate case Decisions. As has been the case historically, residential class ROR have fallen well below the overall system average ROR while commercial and industrial class RORs have exceeded system average significantly. The Company relied on its COSS results when designing rates. Effectively, the Company's proposed rates move all rate classes closer to the system average ROR. Davis, PFT, p. 8.

Wal-Mart took no position on the Company's filed COSS, other than to endorse its use for establishing rates. Wal-Mart stated that COSS-derived rates reflect cost causation, send proper price signals and minimize price distortions. Chriss PFT, p. 19.

The OCC found fault with many of the COSS allocation methodologies employed by the Company. According to the OCC:

1. The minimum distribution system study should be rejected, while distribution costs incurred for poles, lines and transformers should be classified as demand-related.

2. A quarter of transformer costs should be allocated on the basis of usage.

3. Uncollectible expense and operating expenses for customer service and information should be allocated on the basis of class revenues.

Since the OCC considered the COSS to be too impaired to be used to assign revenue responsibility among rate classes, the OCC recommended that bundled, equal percentage revenues increases be applied to all but the smallest rate classes. Should

the Authority rely on the COSS, the OCC recommended that the rate of movement to rate class equality be tempered. Johnson PFT, p. 4.

The OCC also argued that poles and conductors should be classified as 100% demand-related based in large part on a population density argument. In densely populated areas found in Connecticut, utilities tend to oversize conductors when they are installed initially. As such, the incremental cost of adding new customers is minimal because neither new poles nor new conductors are required. Consequently, the cost characteristics of poles and conductors are not consistent with the partial customer classification utilized by the Company. Johnson PFT, p. 17.

The OCC also stated that since minimum system studies contain a certain load-carrying capability, they incorrectly allocate a segment of conductors on the basis of customers. As such, a zero-intercept approach to determining minimum system costs is superior. Finally, the OCC supported classifying transformers as 76% demand and 24% energy. While the typical classification is between demand and customer, the OCC argued that a new operating standard established by the FERC designed to save energy losses in transformers warrants substituting an energy classification for the customer classification. Johnson PFT, pp. 19-21.

The CIEC argued against the OCC's COSS recommendations. The CIEC stated that the COSS methodology adopted by the Company is consistent with the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual (NARUC Manual) and historical treatment approved by the Authority. CIEC Brief, p. 3. The CIEC pointed out that the NARUC Manual requires plant installed to service customers and meet their peak demand, must be segmented into customer and demand related costs. Concerning Accounts 364 through 368, the NARUC Manual at page 90 states that:

> [these accounts] involve *demand and customer costs*. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system … each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.
>
> CIEC Brief, p. 5.

The NARUC Manual recommended that either the minimum intercept method or other methods like the minimum distribution system method be undertaken to discern customer and demand cost components. CIEC Brief, pp. 4 and 5. Continuing, the CIEC quoted earlier Authority Decisions that supported the use of a customer classification.

> The Authority further held in Docket No. 90-12-03, *Application of the Connecticut Light and Power Company to Amend Rate Schedules Phase*

> *II,* in order to achieve an appropriate allocation of distribution plant, "the simplicity of the minimum-size methodology together with its producing results similar to the much more complex minimum-intercept methodology, warrants its continued use by CL&P in future COSSs."[45] The Authority determined that "a genuine, but minimal, distribution system is necessary for a utility to stand ready at no load or to serve nominal loads."

CIEC Brief, p. 9.

The CIEC also provided supportive Authority language used in other electric rate cases stating that:

> The Authority has continued to reaffirm its position. In Docket No. 05-06-04, *Application of the United Illuminating Company to Increase its Rates and Charges*, the Authority rejected the OCC's recommendations that no costs be allocated based on the number of customers.[46] Similarly, in Docket No. 08-07-04, *Application of the United Illuminating Company to Increase its Rates and Charges*, the Authority held that the "OCC has provided no compelling reason to deviate from these established standards"[47] and rejected its request for allocation on the basis of demand only.[48] The OCC's repetition of these repeatedly rejected arguments in this Docket is without support and should be rejected.

CIEC Brief, p. 10

The Authority finds that the population density argument for allocating poles and lines fully on demand is tortured at best. Poles and lines are installed to expand circuits to reach new off-circuit customers. Poles and lines are also required to provide service to new customers situating along existing circuits; albeit not new poles and lines. Regardless of whether pole and lines are new or existing, circuits require both to reach customers. Additionally, it is hard to visualize a demand component to a pole. Demand components exist for poles through the formalistic design of minimum system theory much more than in the practical world of circuit design. Lines or cables have both a customer and demand component. While some minimum size cable is necessary to simply reach all customers, kVA levels differ dramatically between residential neighborhoods and industrial parks.

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45 Docket No. 90-12-03, Application of The Connecticut Light and Power Company to Amend Rate Schedules Phase II, Final Decision (August 1, 1991) Lexis Version at 36.

46 Docket No. 05-06-04, Application of The United Illuminating Company to Increase its Rates and Charges, Decision (issued January 27, 2006) at 114.

47 Docket No. 08-07-04, Application of The United Illuminating Company to Increase its Rates and Charges, Final Decision (February 4, 2009) at 107-108.

48 The Authority has also rejected the application of a demand only to gas plant. Specifically, in its Decision dated June 29, 2011 in Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules, the Authority held that "[t]he OCC's conclusion that trenching costs, 2/3 of current installation costs, should be allocated on peak day demand because of some statistical result defies common sense." Decision, p. 156.

Transformers also have a customer and demand component since transformers are needed to expand circuits to reach customers and sized to reflect differing kVA demands. While the OCC argued that the new efficiency performance standards reduce energy losses, transformers are still sized to satisfy diversified neighborhood peak kVA. The newer transformers will simply provide this service with less energy lost as heat. Additionally, the 24% portion that the OCC proposed to allocate on energy represents the increased cost of a transformer. It does not represent the minor reduction in heat loss actually achieved by the new standard. Johnson PFT, p. 26.

The Company proposed to allocate uncollectible expenses of $5.2 million on the basis of the actual net write-off per rate class. This methodology assigns approximately 82% of the cost to residential rates. Late Filed Exhibit No. 7. The OCC recommended an allocation of uncollectible expense on the basis of class revenues as it is a social cost, and should be spread broadly across the customer base. The magnitude of the uncollectible expense in a given period is affected not only by the number of customers on the system, but also by the amount of revenue billing attributable to each particular type of customer. In addition, the potential for significant impact from individual large accounts should be considered. Direct assignment of the cost does not allocate the expense to cost causers, because the non-payers, by definition, are not paying customers. Therefore, the expense is a social cost which should be spread on a general allocator like revenues. Johnson PFT, pp. 29 and 30.

At the hearing on August 28, 2014, the Authority introduced the concept of allocating uncollectible expense on a socialized, or 100% customer basis. Effectively, every customer would pay the same monthly fee. Tr. 8/28/14, p. 351. In response to cross examination, the Company filed Late Filed Exhibit No. 7, which indicated that under this approach, residential rates would be assigned 90% of the total cost. The Authority accepts the Company's method of allocating uncollectible expense, which utilizes the same methodology approved in recent rate cases. While socialization is a valuable approach, it can wait until a future rate application to be implemented. The Authority may undertake a full COSS and rate design generic review to establish a standardized methodology.

The Authority accepts the COSS submitted by the Company and will rely on it to address rate design issues. The Company's methodology has been consistently applied and approved in multiple rate increase applications and the arguments presented mainly by the OCC have been examined before. Nonetheless, the Company will be directed to submit a zero-intercept study for determining the customer and demand components of various plant accounts in its next rate increase application.

4. Revenue Allocation

a. Company Proposal

The Company allocated revenue increases and determined distribution revenue targets for each rate class based on an evaluation of the excess or deficiency identified in the COSS of each rate class. In general, to reduce the amount of excess or deficiency, and accordingly move the class ROR closer to the equalized ROR, classes with a deficiency (e.g., Rates 1 and 7, defined below) received an increase to their

current distribution revenue increase that was greater than the Company-average of 26.2%. Classes with a revenue excess (e.g., Rates 27, 30, 35, 37, 55-58, defined below) received an increase that was less than the average. Unmetered classes (particularly the street lighting classes for which significant structural redesign and specific other rate design constraints apply) received an increase at or near the Company average. Davis PFT, p. 10.

Based on its proposed rate request, the Company proposed the following Rate class rate increases:

Table 72

		2015						% Change
		Forecasted	Current		Proposed			Proposed
Rate	Schedule/Description	Sales (mWh)	Revenue	$kwh	Revenue	$kwh		vs. Current
1	Residential - Regular	8,461,362	$ 1,556,750	0.1840	$ 1,704,998	0.2015		9.52%
5	Residential - Electric Heat Regular	1,828,279	$ 321,999	0.1761	$ 345,692	0.1891		7.36%
7	Residential - Time-Of-Day	6,156	$ 1,071	0.1740	$ 1,153	0.1874		7.70%
18	Controlled Water Heating *	878	$ 147	0.1674	$ 158	0.1801		7.56%
27	Time-Of-Day General	13,961	$ 2,632	0.1885	$ 2,786	0.1996		5.88%
29	Outdoor Lighting	3,232	$ 775	0.2399	$ 856	0.2647		10.33%
30	Small General	3,275,128	$ 596,593	0.1822	$ 624,316	0.1906		4.65%
35	Intermediate General	1,148,500	$ 179,744	0.1565	$ 184,151	0.1603		2.45%
37	Intermediate Time-Of-Day	1,285,729	$ 195,975	0.1524	$ 201,421	0.1567		2.78%
39	Interruptible Menu	235,489	$ 23,020	0.0978	$ 23,286	0.0989		1.15%
40	Church and School	115,402	$ 20,212	0.1751	$ 21,368	0.1852		5.72%
41	Large Church and School	15,096	$ 2,579	0.1709	$ 2,654	0.1758		2.88%
55	Intermediate TOD Manufacturers	674,097	$ 84,700	0.1256	$ 86,746	0.1287		2.42%
56	Intermediate TOD Non-Manufacturers	2,032,033	$ 264,026	0.1299	$ 270,403	0.1331		2.42%
57	Large TOD Manufacturers	1,077,844	$ 125,898	0.1168	$ 128,122	0.1189		1.77%
58	Large TOD Non-Manufacturers	2,052,918	$ 250,402	0.1220	$ 255,608	0.1245		2.08%
115	Unmetered	53,500	$ 8,820	0.1649	$ 9,425	0.1762		6.86%
116	Street & Security Lighting	92,563	$ 24,445	0.2641	$ 27,884	0.3012		14.07%
117	Partial Street Lighting Service	23,425	$ 3,380	0.1443	$ 3,622	0.1546		7.16%
119	Special Contracts	1,320	$ 492	0.3731	$ 558	0.4226		13.25%
	Total	22,396,911	$ 3,663,662	0.1636	$ 3,895,206	$ 0.1739		6.32%

Exhibit EAD-15, p. 3.

To determine a fair and equitable revenue allocation, the Company considers each rate class' ROR relative to the system average ROR to measure where the excesses/deficiencies exist. The following table illustrates each rate class' existing contribution to overall system ROR.

Table 73

Rate	Class ROR		Rate	Class ROR
1 & 7	1.10%		41	17.12%
5	2.87%		55	11.97%
18	-0.38%		56	13.17%
29	6.17%		57	12.39%
27 & 30	10.47%		58	12.44%
40	6.81%		115	4.45%
35 & 37	12.59%		116 & 117	0.50%
39	6.01%		Special Contracts	7.79%
	* Current System ROR (Company) = 4.16%			
	**Approved System ROR (Company) = 7.24%			

Exhibit EAD 17, pp. 3 and 4.

b. OCC Proposal

The OCC indicated that while the COSS provides useful information for developing the class revenue increases, it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure COSS results. Further, COSS are imprecise instruments. COSS allocate costs to a multiple decimal point level, which could provide a false sense of security about the accuracy of the studies. This conclusion is based on two general reservations regarding embedded COSS. First, some of the costs are classified and allocated on a weak causal basis, and subjective judgment enters into the selection and development of allocation methods. Second, COSS are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various long-run time periods. For these reasons, some degree of judgment may be appropriate in applying the COSS to class revenue increases. "Cost based rates" are best viewed as representing a reasonable band around the COSS results, rather than exact price points. Furthermore, COSS which do not recognize the differences in risk associated with customer classes should be utilized cautiously. Johnson PFT, pp. 40-47

The OCC also disagreed that all classes should be targeted to produce equalized RORs. The Company's required ROR is dependent upon the perceived financial and business risk of the public utility. If the composition of sales by customer class has the effect of producing differing business risks to the utility, then the rationale for equalized relative ROR is not sound. In that situation, it is no more reasonable to expect equal

relative contributions to return than it would be to expect all stocks in a portfolio to make equal contributions to the overall ROR of the portfolio. Id.

The OCC noted that industrial customers are generally riskier to serve due to the larger capital investment required to serve each customer, and the revenue impact from customer losses. Industrial customers' load is more dependent upon domestic or international market conditions. Distributed generation installed by large businesses, as well as manufacturing shutdowns or declining production, reduce the revenue generating capability of distribution plant and ultimately shifts costs onto the more stable residential class. Therefore, the residential class should be expected to produce a lower relative ROR and industrial customers a higher one. Since the revenue targets produced by a COSS presume uniform class RORs, this is an inherent weakness in the practice of strictly moving toward the class RORs in the COSS. Id.

The OCC suggested that several non-cost considerations counterbalance the COSS. First, the COSS does not take into account the risk differences among the classes. Second, the customer class cost relationships are more complicated than the COSS implies. Third, CL&P's current residential rates are very high, and implementing an above system average percent increase on the residential class will exacerbate the situation. According to the Energy Information Administration, Connecticut has the second highest residential electric rate in the United States (behind only Hawaii). Id.

The OCC pointed out that there are a number of bill items that impact distribution, but are recovered in other billing categories, such as non-bypassable federally mandated congestion charges (NBFMCC). In the OCC's view, these bill items feature: (a) cross subsidization among the rate classes; (b) charges for programs that impact distribution rates; and (c) costs that should properly be charged to distribution. Examples of this include the following.

- The DG program: This program includes payment of gas distribution charges and waiver of backup charges for the large user participants. Most of the ratepayers who pay the cost of this subsidy do not qualify for participation in the program. In addition, DG program participants greatly reduce their usage of electricity, leaving the remaining ratepayers to shoulder the share of distribution costs previously supported by the DG participants.
- Storm resiliency: In this case, CL&P includes an additional $44 million for resiliency that it would charge to NBFMCC until the next rate case after this one. CL&P has also charged resiliency costs to NBFMCC in a pending proceeding (Docket No. 14-02-01, PURA Semi-Annual Reconciliation of the Federally Mandated Congestion Cost and Generation Service Charges of The Connecticut Light and Power Company and The United Illuminating Company). Residential customers pay a disproportionate amount of NBFMCC costs, and distribution costs previously recovered from residential users through the NBFMCC appear to reflect equalized rates of return. Because the charges were outside the COSS, residential customers do not receive credit in the COSS results for the returns paid through the NBFMCC.

Id.

Additionally, the OCC stated that CL&P's proposed distribution percentage revenue changes are much higher for residential customers than commercial and industrial (C&I) customers. The OCC recommended setting the increase 120% higher than the system average percent increase for the following Rates: 18, 25, 39, 116, 117, and 119. The OCC further recommended distributing the remaining portion of the revenue increase on an equal percentage basis to the remaining classes (6.2% based on the Company's filed request). Capital investments for resiliency, upgrading distribution facilities, and replacement of outdated distribution infrastructure are among the drivers of the increased rates. All customer classes should contribute to the rate increases supporting these upgrades on an equivalent basis. The OCC stated that, even assuming that the proposed rate increases rely on the COSS targets, CL&P's proposed class revenue increases represent movement that is too rapid and produces excessive rate impacts on residential customers. The alternative COSS proposed by the OCC reduced the residential revenue deficiency by almost 40%. Given the reduction in the residential target, the severity of the proposed movement to cost of service for below-cost classes can be relaxed. Id.

As an alternative to its proposal, the OCC recommended the following revenue increase allocation parameters: set the residential total bill revenue increase no higher than 118% of the system average percentage (approximately a 7.5% percent increase based on the Company's filed request); limit all below-cost class increases to 120% of system average; and set a floor of 75% of system average percent for all above-cost classes. This would produce a 28% increase in distribution revenues for the residential class or approximately 110% of the system average distribution increase, which would represent reasonable movement toward the COSS results, particularly taking into account the adjustments recommended for the COSS methodology. Id.

c. Position of the Parties

In addition to the positions/alternative proposal offered by the OCC above, the CIEC and the BETP provided comments specific to revenue allocation.

i. Connecticut Industrial Energy Consumers

The CIEC indicated that the RORs of the residential classes are significantly below the system average. In contrast, rates imposed upon C&I rate classes provide above-average ROR. As a result, the C&I classes are subsidizing the residential classes and providing, in most instances, RORs, at current rates of approximately three times the system average. The total subsidy paid by C&I classes under current rates exceeds $20 million annually. Undoubtedly, over the past decade, large C&I customers have paid tens of millions of dollars in excess of their actual cost of service. In order to continue to promote rate unity and properly allocate distribution costs among rate classes, the Company's allocation should be approved. CIEC Brief, pp. 15 and 16.

ii. Bureau of Energy & Technology Policy

The BETP is concerned with the proposed allocation of the overall rate increase among CL&P's customers and recommended narrowing the difference between the

average increase for different rate classes, especially for residential and street lighting customers. CL&P's COSS should be regarded as a guide to ratemaking, but not the only factor considered. Other important factors that must be considered are rate impacts, equity, continuity, efficiency, and understandability. The BETP disagrees with CL&P that the ROR for each rate class should be equal. Electricity use for residential customers is more predictable than C&I customers, whose usage is much more affected by economic trends. The BETP recommended lowering the overall increase to Residential Rate 1 and Street Lighting Rate 116 customers to no more than 125% of the average rate increase for all customers to reduce the burden on residential customers and municipalities. BETP Brief, pp. 10-13.

d. Authority Analysis

The Company's COSS will be relied upon by the Authority for designing rates. The Authority finds that to reduce interclass subsidies, all classes should be moved closer to their cost to serve, or closer to the system average ROR, while applying the principles of rate gradualism. While gradualism is certainly a debatable concept, the Authority considers the impacts on each rate class relative to the system revenue increase approved herein. The approved revenue requirement increase of $130.172 million will increase the current total revenues of $3,663 million by approximately 3.5%. See, Table 74. Since the Authority is allowing a total system-wide rate increase of approximately 3.5%, it would suggest that the rate classes that are contributing a lower relative return will be allocated a revenue requirement increase in excess of that amount, and vice versa for higher contributing classes. The farther the class is from the system average, the larger the percentage increase/decrease necessary to align the class revenues to the average.

The Company demonstrated, through the results of its COSS, the need to assign a higher proportion of the distribution rate increase to Rates 1, 7, 5, 18, 115, 116 and 117 and a lower portion of the rate increase to rates 27, 30, 35, 37, 41, 55, 56, 57 and 58. This determination was made through analysis of each rate class' current contribution to the Company's revenue requirements. As shown, Rates 1, 7, 5, 18, 115, 116 and 117 are contributing a ROR that is at least 200% lower than the system ROR. Rates 27, 30, 35, 37, 41, 55, 56, 57 and 58 have a class ROR that is at least 200% higher than the system ROR. To reduce inequities between classes, it is necessary to align the rate classes as close to the system ROR as possible.

The Authority accepts the Company's proposed allocation methodology of its rate request among the customer classes. CL&P has provided a reasonable proposal which is generally fair to all rate classes while moving the RORs closer to the Company's average. The Company allocated a higher than average (6.35%) increase to Rates 1, 5, 7, 18, 29, 115, 116, 117 and 119, which are the rate classes showing the lower than system RORs in the COSS. Conversely, the Company allocated a lower than average increase to Rates 27, 30, 35, 37, 39, 40, 41, 55, 56, 57 and 58. The proposed allocation appropriately shifts more revenue responsibility to the residential customer class while keeping the rate increase to approximately 50% greater than the average, which the Authority does not view as excessive, given the current ROR of 1.1%. The highest increases of 14.07% and 13.25% are proposed for the low volume Street &

Security Lighting and Special Contract classes, again, not excessive relative to the overall increase and their current ROR of 0.50%.

The allowed increase (not including the ROE penalty) is approximately $96 million less than the Company's original proposal of $231.6 million, on which they based their rate design proposal. Therefore, the revenue allocation to the individual rate classes will change as a result of the Authority's reduction to CL&Ps proposal. To maintain the equity balance previously discussed, the Authority will apply the adjustment to the proposed revenue increase to the rate classes by holding intact each rate class' overall percentage increase relative to the average percentage increase for all customers from CL&P's original proposal. For example, for Rate 1, CL&P proposed an overall percentage increase of 9.52%, which is 51% higher than the overall proposed rate increase of 6.32%. By holding the relationship of the increase to Rate 1 relative to the overall allowed increase of 3.51%, the adjusted increase for Rate 1 is 5.51%. The following table details this methodology applied to all of CL&P's rate classes[49]:

Table 74

Rate Year Revenue and Rate Class Allocation

			(A)		(B)		{C}	(D)	{E}	(F)	(G)
									Authority Adjustment		
		2015 Forecasted	Current		Proposed		% Change Proposed	Rate Class to average %	% Allowed Vs. Current	Allowed Revenue	Adjustment $
Rate	Schedule/Description	Sales (mWh)	Revenue	$kwh	Revenue	$kwh	B / A-1	(C) / (H)	D * I	(E+1)*A	(F)-(B)
1	Residential - Regular	8,461,362	$ 1,556,750	0.1840	$ 1,704,998	0.2015	9.52%	151%	5.51%	$ 1,642,522	$ (62,476)
5	Residential - Electric Heat	1,828,279	$ 321,999	0.1761	$ 345,692	0.1891	7.36%	116%	4.26%	$ 335,707	$ (9,985)
7	Residential - Time-Of-Day	6,156	$ 1,071	0.1740	$ 1,153	0.1874	7.70%	122%	4.45%	$ 1,119	$ (35)
18	Controlled Water Heating *	878	$ 147	0.1674	$ 158	0.1801	7.56%	120%	4.37%	$ 153	$ (5)
27	Time-Of-Day General	13,961	$ 2,632	0.1885	$ 2,786	0.1996	5.88%	93%	3.40%	$ 2,721	$ (65)
29	Outdoor Lighting	3,232	$ 775	0.2399	$ 856	0.2647	10.33%	163%	5.98%	$ 822	$ (34)
30	Small General	3,275,128	$ 596,593	0.1822	$ 624,316	0.1906	4.65%	74%	2.69%	$ 612,633	$ (11,683)
35	Intermediate General	1,148,500	$ 179,744	0.1565	$ 184,151	0.1603	2.45%	39%	1.42%	$ 182,294	$ (1,858)
37	Intermediate Time-Of-Day	1,285,729	$ 195,975	0.1524	$ 201,421	0.1567	2.78%	44%	1.61%	$ 199,126	$ (2,295)
39	Interruptible Menu	235,489	$ 23,020	0.0978	$ 23,286	0.0989	1.15%	18%	0.67%	$ 23,174	$ (112)
40	Church and School	115,402	$ 20,212	0.1751	$ 21,368	0.1852	5.72%	91%	3.31%	$ 20,881	$ (487)
41	Large Church and School	15,096	$ 2,579	0.1709	$ 2,654	0.1758	2.88%	46%	1.67%	$ 2,622	$ (31)
55	Intermediate TOD Manufacturers	674,097	$ 84,700	0.1256	$ 86,746	0.1287	2.42%	38%	1.40%	$ 85,884	$ (862)
56	Intermediate TOD Non-Manufacturers	2,032,033	$ 264,026	0.1299	$ 270,403	0.1331	2.42%	38%	1.40%	$ 267,715	$ (2,687)
57	Large TOD Manufacturers	1,077,844	$ 125,898	0.1168	$ 128,122	0.1189	1.77%	28%	1.02%	$ 127,185	$ (937)
58	Large TOD Non-Manufacturers	2,052,918	$ 250,402	0.1220	$ 255,608	0.1245	2.08%	33%	1.20%	$ 253,414	$ (2,194)
115	Unmetered	53,500	$ 8,820	0.1649	$ 9,425	0.1762	6.86%	109%	3.97%	$ 9,170	$ (255)
116	Street & Security Lighting	92,563	$ 24,445	0.2641	$ 27,884	0.3012	14.07%	223%	8.14%	$ 26,435	$ (1,449)
117	Partial Street Lighting Service	23,425	$ 3,380	0.1443	$ 3,622	0.1546	7.16%	113%	4.14%	$ 3,520	$ (102)
119	Special Contracts	1,320	$ 492	0.3731	$ 558	0.4226	13.25%	210%	7.66%	$ 530	$ (27)
											$ -
	Total	22,396,911	$ 3,663,662	0.1636	$ 3,895,206	$0.1739 (H)	6.32%	100% (I)	3.66%	$ 3,797,627	**$ (97,580)**
									I = (B+M)/A-1		
		(J)	Company Request (Application)		$ 231,545						
		(K)	Allowed Rate Increase		$ 134,565						
		(L)	Increase in Other Revenue		$ 600						
		(M)	Adjustment to Rate Revenue		**$ (97,580)**	= (J-K)+L					

The Authority notes that the transfer of $15.3 million of system resiliency expenses will reduce the overall increase once it is implemented. Because the system resiliency charges will not be removed from the NBFMCC charge until it is reset in January, the Company shall return to customers the system resiliency-related revenues it collects through the NBFMCC in December 2014.

[49] The Authority made further adjustments to the approved revenue requirement for 2016 previously established in the Proposed Final Decision of approximately $489,000. In Section II.J.5., Rate Design, the Authority directs the Company to allocate the net decrease to Rate 116.

5. Rate Design

a. Company Proposal

The Company proposed rate changes that are designed to recover its Rate Year distribution operating deficiency and previously approved storm costs and system resiliency costs commencing on December 1, 2014. The Company developed the proposed distribution rates by allocating the revenue increases and designing rates for each rate class in a manner that achieves a balance among a number of interrelated objectives, based on an evaluation of the cost of service, current rates and impacts of changes to rates in each class. In particular, the Company sought to move rates in each rate class closer to their actual cost of service, both at a total class level and with respect to the prices for distribution service within each rate class. By applying the principles of equity and cost causation in allocating cost responsibility among rate classes, as well as the principle of gradualism in setting total class revenues, the Company reduced the revenue excess or deficiency and moved the ROR for each rate class closer to the Company average. Those rate classes with below system average RORs (as computed within the COSS based on current rates) have been allocated a greater than average percentage distribution increase, while those classes with above system average RORs have been allocated a lower than average percentage increase. Davis PFT, pp. 1-3.

CL&P indicated that its rate design also moves current rates closer to cost-of-service levels within rate classes by generally decreasing or eliminating per kWh charges, and moving customer and demand charge rates closer to their cost-of-service levels. The Company redesigned residential and small general service customer rates based on the COSS. Specifically, these rates were redesigned to increase the amount of distribution costs collected through customer charges and, where applicable, demand charges, and thereby reduce the recovery of fixed distribution costs through volumetric charges. In redesigning specific rates within each class, application of these principles more equitably align the recovery of fixed distribution costs with an appropriate, corresponding rate mechanism. Id.

Overall, the proposed rates were designed to collect a total distribution revenue increase of $231.6 million, and when combined with a corresponding reduction of $15.3 million to the NBFMCC, will represent an overall average increase to total bills of 5.9%. Id. CL&P proposed to move the ROR of each rate class closer to the Company's average ROR, and reduce the amount of fixed distribution costs recovered through volumetric charges. The Company gave additional consideration to the allocation of costs and redesign of rates within the street lighting class due to its proposed structural changes. CL&P asserted that its proposal achieves a balance between assigning an appropriate level of cost responsibility to each rate class, maintaining reasonable bounds around rate changes and customer impacts, and addressing fixed cost recovery through rates as appropriate. Davis PFT, p. 8.

CL&P proposed the following rate design changes for the residential classes:

Table 75

Comparison of Current Rates vs Proposed Rates				
	Current	Proposed	Proposed vs. Current	
	Rate	Rate	Difference	% Chg
Rate 1 - Residential Electric Service				
Customer Charge	$16.00	$25.50	$9.50	59.38%
Energy Charge All kWh	$0.16165	$0.16591	$0.00426	2.64%
Rate 5 - Residential Electric-Heat				
Customer Charge	$20.25	$30.00	$9.75	48.15%
Energy Charge All kWh	$0.15768	$0.16176	$0.00408	2.59%
Rate 6 - Residential Electric Heat TOD				
Customer Charge	$20.25	$30.00	$9.75	48.15%
Energy Charge On-Peak kWh	$0.15768	$0.18496	$0.02728	17.30%
Energy Charge Off-Peak kWh	$0.15768	$0.14996	($0.00772)	-4.90%
Rate 7 - Residential TOD				
Customer Charge	$16.00	$25.50	$9.50	59.38%
Energy Charge On-Peak kWh	$0.18485	$0.18911	$0.00426	2.30%
Energy Charge Off-Peak kWh	$0.14985	$0.15411	$0.00426	2.84%

Application, Exhibit EAD-3.

For Rate 1, CL&P set a distribution rate revenue target of $570.4 million, an increase of $148.2 million or 35.11% over its current distribution revenue of $422.5 million. Application, Exhibit EAD-2. CL&P also proposed to collect the increase through a 59% increase to the Rate 1 Customer Charge and a 2.64% increase to the per-kWh Charge.

b. Office of Consumer Counsel Proposal

The OCC disagreed that the Company's proposed customer charge is cost-based. This relates to the OCC's assertion that the Company's COSS is faulty, particularly with respect to the classification of distribution infrastructure as customer-related. If the COSS classified distribution facilities on a full demand basis, without classifying the plant costs as customer-related, the study would support a customer charge no higher than $11.68. Therefore, both the current and proposed customer charges are above cost. Even among those utilities that utilize a minimum system study for the COSS, it is rare that the customer charge is fixed at a level which recovers the cost of secondary and primary voltage conductors, poles, and transformers. Further, the fact that the law now requires a revenue decoupling mechanism should lead to the conclusion that the motivation for continued increases in fixed charges no longer exists. Johnson PFT, pp. 33-40.

The OCC proposed that the customer charge should only recover costs which directly vary with the number of customers such as: O&M expense for meters, services, meter reading, and customer accounting, and return and depreciation on meter and service investment, minus credits for customer deposits and related deferred federal income taxes. General overhead, such as administrative and general expense, should be excluded from the customer charge computation, because these costs do not vary

directly with number of customers. The OCC proposed a maximum $11.68 customer charge. Id.

The OCC stated that with the exception of its access rationing role, the customer charge provides no price signal relevant to resource allocation. Because the electric utility cost structure is dominated by costs which vary with changes in demand and annual electric load, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures that a greater proportion of costs are recovered through a usage-sensitive price. A lower customer charge is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low usage residential customers. Many such customers often reside in older multi-family structures served by largely depreciated meters and service drops. Id.

The OCC pointed out that low-use customers in Rate 1 will face the largest percentage bill increases from the proposed customer charge increase (for instance, a 16% increase in the total bill for 300 kWh customers. According to the OCC, imposing a larger increase on customers who impose a minimal demand on the system, and may be the least capable of affording the rate increase, is inequitable. The concept of fixed vs. variable costs is not a very meaningful distinction for purposes of utility cost analysis. Inasmuch as the majority of customer usage within the residential class falls within a reasonable range of load factors, a kWh usage charge is likely to accomplish approximately the same purpose as a demand charge. Id.

The OCC recommended that the Customer Charge for Rate 1 be set no higher than $11.50, which is in line with the COSS service results. If the Authority is reluctant to reduce the customer charge, at the least, the current customer charge should not be increased. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayer with a greater ability to control his/her bill on the basis of usage. For that reason, an excessive customer charge can promote wasteful energy consumption. Connecticut has numerous statutory programs which provide incentives for increased energy efficiency, evincing a staunch policy in favor of reduced energy consumption. The increase in customer charge runs counter to that state policy. The OCC calculated that there is a 10% reduction in the life cycle present value savings under the Company's pricing vs. the OCC's proposed charge of $11.50. At a practical level, the lower potential savings under the Company's increased customer charge represents an extra incentive amount, which may have to be paid by state programs to achieve the expected demand reductions. Id.

c. Position of the Parties

The OCC, BETP, ENE and AG all strongly objected to the 59% increase in the customer charge. The Authority also received an unprecedented number of comments from customers, public officials and consumer advocates on the proposed rate increase. An overwhelming majority of customers who submitted public comment or testified at the public hearings or filed written comments strongly opposed the proposed rate increase, especially the 59% increase in the residential Customer Charge.

i. Office of the Attorney General

The AG commented that CL&P's proposal to increase the customer charge by 60% is unduly burdensome for residential ratepayers and is poor public policy. Further, due to the implementation of full sales decoupling in the instant proceeding, increasing the customer charge is completely unnecessary to further the intent of decoupling. AG Brief, p. 20.

ii. Office of Consumer Counsel

The OCC indicated that CL&P's rate design proposal is contrary to the state's energy policy and adversely impacts small electricity users, low-income and fixed income and elderly customers. CL&P's efforts to radically increase the customer charge is also "anti-conservation," as it attempts to shift costs currently recovered through commodity rates to fixed monthly charges that do not vary by usage levels. OCC Brief, p. 4. Further, the OCC pointed out that CL&P's Rate 1 Customer Charge is much higher than in the other New England states. The OCC urged the Authority to consider the actual impacts of this dramatic increase in CL&P's customer charge and whether those impacts are consistent with state policy, rather than adhering to an ideological path that is clearly inconsistent with state policy. OCC Brief, 115 and 116.

iii. Environment Northeast

ENE stated that the Company's proposed increases in the fixed charges do not align with Connecticut's energy efficiency and clean energy policies and, therefore, are not in the best interest of CL&P's customers. ENE supported CL&P's request for full revenue decoupling because it will help remove any Company sales-related disincentive to promote energy efficiency and distributed generation. Decoupling is also an effective cost-recovery alternative to CL&P's proposal to increase the fixed charge. ENE argued that the proposed high fixed charge increases do not align with state energy policy for several reasons: (1) they reduce customer control over electricity costs, (2) they are unfair to energy efficient (or low-use) customers (3) they reduce the value of existing efficiency or on-site generation investments, (4) they reduce the economic signal to customers to invest in energy efficiency and (5) they may harm the cost-effectiveness of the state's energy efficiency programs. ENE Brief, pp. 4-6.

ENE recommended that the Authority design rates by: (1) lowering the fixed customer charge in the residential classes to at least $11.50, as recommended by the OCC; (2) rejecting the excessive fixed charge increases in the small business and church and school customer classes; (3) applying any approved rate increase solely to the variable charges, which is the portion of the distribution bill that the customer can control; and (4) requiring CL&P to implement revenue decoupling with a full reconciliation mechanism between allowed and actual revenue. ENE Brief, p. 7.

iv. Bureau of Energy & Technology Policy

The BETP recommended that the Authority: (1) reduce CL&P's proposed fixed monthly service charge increase for all residential and small commercial customers; (2) reduce the burden on residential customers and municipalities by narrowing the

difference in the average rate increase among rate classes; (3) approve CL&P's decoupling proposal; and (4) increase the rate differential for on- and off- peak charges in residential time-of-use Rate 7. The BETP indicated that the priorities outlined in the 2013 Comprehensive Energy Strategy (CES) form the basis for their recommendations, namely energy efficiency, increasing system reliability with DG and advancing the development of in-state renewable energy resources. BETP Brief, pp. 2-4.

The BETP opposed CL&P's proposed fixed monthly service charge for three main reasons. First, increasing the fixed monthly service charge unfairly penalizes certain classes of customers, specifically those customers who use the least electricity, such as small businesses, churches and schools, and people on low or fixed incomes. Second, increasing the fixed monthly service charge undermines a customer's ability to obtain the full benefits of key energy-saving programs encouraged in the 2013 CES, such as energy efficiency. Third, CL&P's proposal to increase the fixed monthly service charge works against the state's efforts to increase the deployment of in-state, local clean energy resources like solar, fuel cells, combined heat and power, and other similar technologies, as detailed in the 2013 CES. Id.

d. Authority Analysis

i. Residential

The Authority finds that applying this rate class increase in an across-the-board manner to the residential rate classes is a reasonable approach to increasing the distribution charges in a more moderate manner than the Company's proposal. The Authority fully agrees with the Company that the general objective of rate design is "to continue to move distribution rates among and within classes to better reflect the cost responsibilities identified in the Company's cost of service study." While the Authority generally prefers an approach that moves rates towards increased fixed cost recovery, it must consider the customer impact of how the rate increase is applied. The Company made a significant leap in the 2008-2009 timeframe by implementing a 60% increase in the residential Customer Charge, from $10 per month to the current charge of $16. Response to ENE-6. Further, the Authority is no longer mandated to implement decoupling through increased fixed charges, but instead required to implement full revenue decoupling. See, Section II.H, Decoupling. Given the level of customer opposition to the fixed charge design, the current Customer Charge levels and the implementation of a decoupling mechanism in the instant case, a more gradual approach is warranted. Therefore, the Authority will approve customer charge increases for Rates 1, 5 and 7 that reflect the application of the average distribution rate class increase across-the-board.

The Authority illustrates this approach in the case of Rate 1 (and TOD companion Rate 7). As shown in Table 74, the Authority lowered CL&P's proposed distribution revenue increase for Rates 1 and 7 by approximately $62.5 million, which lowers CL&P's distribution revenue target from $570.8 million to $508.3 million. The proposed distribution rate increase for Rate 1 and 7 will therefore be decreased from 35.1% to 20.3% ($508.3 million / $422.5 million in current revenue). Applying this increase in an across-the-board manner in the residential rate classes, or 20.3% in the case of Rate 1 and 7, produces a customer charge of approximately $19.25. See,

Table 75 and Application, Exhibit EAD-2, line 21. Applying the Rate 5 adjusted distribution increase of approximately 17.2% [($103.3 million - $10 million) / $79.6 million in current revenue] across-the-board will raise the customer charge from $20.25 to approximately $23.73. See, Table 75 and Application, Exhibit EAD-2, line 22. The Authority will further adjust the Rate 5 Customer Charge by rounding it to $23.75.

Several parties argued that decoupling reduces the need for large increases in fixed charges, as the Company will be assured the revenue recovery through the decoupling mechanism. Now that the Company is shielded from the effects of revenue variability due to decoupling, it is tempting to dismiss the need to continue the move towards fixed costs recovery. While that is true to some extent, the Authority cautions on the unintended consequences of over-relying on a decoupling mechanism and, consequentially, eroding cost-based ratemaking principles. In a decoupling environment, lower customer charges and higher variable charges increases ratepayers' exposure to large swings in sales related to conservation, distributed generation, weather and the economy. For example, in the event of a much warmer than normal summer, a portion of the revenue recovered from residential customers may be returned to commercial and industrial (C&I) customers.

As such, the Authority is against lowering the customer charges from current levels, or eliminating the customer charges altogether. While the Authority supports the state's energy policy goals, they do not justify abandoning well-established cost of service principles that promote customer equity and cost causation. Intentionally increasing fixed cost recovery on a volumetric basis does not reflect cost causation and misallocates demand cost responsibility, thereby increasing inequities within a class. Distribution costs do not vary in proportion to the energy delivered, but are only a function of the number of customers and their peak demands. If rates are designed in large part to maximize customers' ability to control their bill, then those costs are shifted to other customers or perhaps re-charged to the customer the following year through the decoupling mechanism. Regarding some of the Parties assertions that increasing fixed charges unfairly burdens low-use customers, the Authority notes that not increasing fixed charges has the effect of shifting that cost responsibility to the remaining customers in that rate class. In approving the overall rate design, the Authority must balance the competing interests of all customers.

Lastly, more investigation is needed regarding how customers perceive price signals, both at the overall bill level and on the billing component level. It is not clear what the magnitude of price signals will need to be to effectuate change in customer usage behavior. The Authority can use anecdotal evidence based on customer migration levels from Rate 1 to 7 that the potential for a 10% savings has not induced a large customer migration to TOD pricing.

The approved revenue requirements, revenue allocation and rate design changes discussed above will result in an increase of approximately $7.12 per month[50]

[50] Bill impact estimate is based on a current customer bill of $129.16 for 700 Kwh of usage and an average increase of 5.51%, totaling approximately $136.28 under new rates. See, Exhibit EAD-6, p. 1.

for the average residential customer's bill. Under the approved rate design, ample opportunity remains for customers to conserve and save as the vast majority of customers charges are priced on a volumetric basis. A $19.25 Customer Charge, the only fixed component, relative to a total customer bill of $136.28 is approximately 14 percent. Therefore, approximately 86 percent of the bill remains subject to immediate savings if kWh consumption is reduced.

ii. Commercial and industrial

Many of the arguments raised by the Parties on increasing the fixed charge in the residential rate classes also apply to the smaller commercial rate classes. The following table illustrates the impact of the customer charge proposal for the smaller commercial rates:

Table 76

Comparison of Current Rates vs Proposed Rates				
	Current	Proposed	Proposed vs. Current	
	Rate	Rate	Difference	% Chg
Rate 27 - Small TOD General Service				
Customer Charge	$38.50	$55.00	$16.50	42.86%
Demand Charge Greater Than 2 KW	$9.34	$15.35	$6.01	64.35%
Energy Charge On-Peak kWh	$0.19899	$0.16296	($0.03603)	-18.11%
Energy Charge Off-Peak kWh	$0.11493	$0.09941	($0.01552)	-13.50%
Rate 30 - Small General Service				
Customer Charge	$38.50	$55.00	$16.50	42.86%
Demand Charge Greater Than 2 KW	$12.51	$18.52	$6.01	48.04%
Energy Charge First 300 Hours Use	$0.12616	$0.10836	($0.01780)	-14.11%
Energy Charge Over 300 Hours Use	$0.12616	$0.10836	($0.01780)	-14.11%
Rate 40 - Church and School				
Customer Charge	$47.50	$70.00	$22.50	47.37%
Energy Charge All kWh	$0.16473	$0.16980	$0.00507	3.08%

Application, Exhibit EAD-3.

The Authority finds that, similar to the proposed increase to the residential fixed charges, the percentage increase proposed for customer charges for these rates are high, in excess of 40%. As such, the Authority will direct the Company to apply an increase to the fixed charge component for Rates 27, 30 and 40 in one of the following manners: (a) at the individual rate classes distribution percentage increase; or (b) at the overall distribution increase percentage, if higher than (a).

Except as modified above, the Authority finds the Company's rate design proposal acceptable, as it continues the move towards more equitable, cost-based rates while mitigating the impact that such increases have on customers. CL&P appropriately reallocated the revenue responsibility of the rate classes closer to the system average without excessive impacts. The customer and demand charges are fully cost-based,

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Actual bill impact is subject to slight change upon review of the final Rate Plan submitted by the Company.

where possible, and the customer and/or demand charges for the remaining classes move closer to the cost-based rates without excessive impact on customers on either spectrum of usage. The Company will be directed to submit a final rate plan (Rate Plan) that incorporates the following modifications:

1. The Company will file a final-rates COSS reflecting rate year billing determinants, the financial profile approved in this Decision and the then current rates developed in accordance with the Rate Plan approved herein.

2. The Company will include adjustments to Other Revenue for reconnection fee revenue and pole attachment revenue discussed in Section II.J.2. Operating Revenue, when designing rates.

3. The TOD rate structure proposed by the Company as Rate 5 is denied; Rate 7 will continue to be available to either Rate 1 or 5 customers.

4. The approved customer charge for Rates 1 (and associated Rate 7) and 5 are $19.25 and $23.75, respectively.

5. The Company will apply an increase to the fixed charge component for Rates 27, 30 and 40 in one of the following manners: (a) at the individual rate classes distribution percentage increase; or (b) at the overall distribution increase percentage, if higher than (a).

6. The allocation of pro forma revenues to the rate classes will be set in accordance with the directives in Section II.J.4, Revenue Allocation.

7. The Company will apply the increase associated with the adjustment in pole attachment revenue to distribution revenues before designing rates.

8. The Company will apply the net decrease of approximately $489,000 to the 2016 revenue requirement level to offset the revenue allocation to Rate 116 when designing rates, since this rate class received the largest percentage rate increase.

9. The compliance filing for the Rate Plan will consist of the following:

    a. Testimony
    b. Schedule E-1, Scored and Unscored Proposed Tariffs
    c. Schedule E-2.0 Revenue Summary
    d. Schedule E-2.1 Detailed Revenue Summary
    e. Schedule E-2.2 Revenue Calculation
    f. Schedule E-2.3 Typical Bill Comparisons
    g. Schedule E-6.0 COSS
    h. Schedule E-6.0 COSS – Unity
    i. Standard Revenue Proof Exhibits

The distribution rate increase will become effective December 1, 2014; however, new rates will not be implemented until after final approval of the Rate Plan. Since the

Company will be submitting full year rates to be recovered over less than a full year period, it may encounter a shortfall in collecting the approved distribution rate increase. Any such shortfall may be reconciled in the decoupling mechanism approved herein. The Authority notes that the customer bill impact of a portion of the distribution rate increase will be mitigated by a subsequent decrease of the storm related costs which will be removed from the NBFMCC effective January 1, 2015. The Company shall consider the net impacts of the revenue recovery transfer between the NBFMCC and the distribution rates in their revised rate filing and provide this information to the Authority.

6. Pole Attachment Rates

a. Company Proposal

Pursuant to Order No. 1 in the Decision dated September 12, 2013 in Docket No. 11-11-02, Petition of Fiber Technologies Networks, L.L.C. for Authority Investigation of Rental Rates Charged to Telecommunications Providers by Pole Owners (Fibertech Decision), the Company proposed to change its methodology for calculating pole attachment fees under its Community Antenna Television (CATV) pole attachment tariff (CATV Rate), Telecommunications pole attachment tariff (Telecom Rate) and Municipal pole attachment tariff (Municipal Rate). The current pole attachment tariffs provide recurring and non-recurring charges for pole attachments. Recurring charges are typically fees for rental of pole space, and non-recurring fees typically include items such as make-ready costs. Municipal Rate customers are allowed an exemption from pole attachment fees for their first attachment on any pole; therefore, the recurring fees apply predominantly to CATV and Telecom attachers. Pole attachments under all three tariffs are subject to non-recurring fees for make-ready work and other charges for services, as outlined in the tariffs.

To implement Order No. 1 in the Fibertech Decision, the Company proposed adjustments to the formula rate for Telecom attachers consistent with the methodology in the Federal Communications Commission's Report and Order on Reconsideration, In the Matter of Implementation of Section 224 of the Act (WC Docket No. 07-245), and A National Broadband Plan for Our Future (GN Docket No. 09-51), adopted and released April 7, 2011 (Pole Attachment Order). To achieve parity between the Telecom Rate and the CATV Rate, the Company applied factors to the pole attachment Telecom Rate methodology calculations to be consistent with the factors applied in the CATV Rate calculations. Davis PFT, pp. 20-24. The following tables detail CL&P's calculation of the Cable Rate and the Telecom Rate:

Table 77

CATV Formula						
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate
	=	8.11%	x	$643.57	x	31.73%
		Fully Owned		Jointly Owned*		
	=	**$16.56**		**$8.28**		
* Fully Owned Rate / 2						

Table 78

Telecom Formula								
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate	x	Conversion Factor
Maximum Rate (Urban)	=	11.723%	x	$643.57	x	31.73%	x	69.18%
		Fully Owned		Jointly Owned*				
		$16.56		**$8.28**				
Maximum Rate (Non-Urban)	=	17.872%	x	$643.57	x	31.73%	x	45.38%
		Fully Owned		Jointly Owned*				
		$16.56		**$8.28**				
* Fully Owned Rate / 2								

As shown above, CL&P calculated pole attachment rates for the CATV Rate and Telecom Rate of $16.56 for a fully owned pole and $8.28 for a jointly owned pole, respectively. For the CATV Rate, CL&P calculated a space factor of 8.11%, based on the space occupied by one attachment (typically a foot) as a percentage of the total usable space (estimated by CL&P to be 12.33' across its system). CL&P calculated a net cost of a bare pole of $643.57 using a combination of 90% of the embedded cost of a pole of $609.62, and 10% of the marginal (replacement) cost of a pole of $949.14. The Carrying Charge Rate of 31.73% grosses the rate up for elements such as administrative expense, maintenance, depreciation, taxes and rate of return on investment. Application, Exhibit EAD-10.

For the Telecom Rate, CL&P calculated a space factor of 11.723% for poles situated in urban areas and 17.872% for poles situated in non-urban areas, based on the following formula:

$$\text{Space Factor (Urban/Non-Urban)} = \frac{\text{Space Occupied} + \left[\frac{2/3 \times \text{Unusable Space}}{\text{No. of Attaching Entities}}\right]}{\text{Pole Height}}$$

CL&P used 27.67' as the unusable space assumption, a pole height assumption of 40' and 3 attaching entities for the urban space factor and 5 attaching entities for the non-urban space factor. CL&P also applied an urban conversion factor of 69.18% and a non-urban conversion factor of 45.38%. Application, Exhibit EAD-10. CL&P stated that applying the new methodology to calculate the Telecom Rate shows that it becomes essentially the same as the CATV Rate, regardless of whether the telecom attachment is classified as "urban" or "non-urban." Davis PFT, pp. 20-24. CL&P's proposed reduction in the Telecom Rate would reduce the amount of pole attachment fee rental revenue received from pole attachments by approximately $164,000 annually. The Company imputed an expected change to the Telecom Rate into its proposed rates.

The Company's proposal converts the stated rate to a formula-based rate, such that the rate and revenue received from pole attachment will vary annually as costs, numbers of attachments and other factors change. The Company also proposed to flow any revenue variation from pole attachment fees that may occur through changes to the rate, as well as changes in numbers of attachers through the Company's decoupling mechanism. The pole attachment rates are billed on a semi-annual basis. Given the proposed December 1, 2014 effective date for implementation of the proposed pole attachment rate methodology, the Company plans to notify customers of the change in rate, and provide prorated bill adjustments for December 2014. On an ongoing basis, rate changes based on the proposed methodology would be calculated, and notice of rate changes would be provided annually for rates in effect on January 1 of each year. Id.

b. NECTA Proposal

The New England Cable and Telecommunications Association, Inc. (NECTA) opposed CL&P's calculation of the CATV Rate and Telecom Rate, indicating that the Company did not follow the Fibertech Decision or the Pole Attachment Order. According to NECTA, CL&P significantly raised the CATV Rate, created its own formula, and lowered the Telecom Rate only enough to meet the inflated CATV Rate. Glist PFT, pp. 5-12. NECTA also stated that CL&P blended parts of a 20-year old rate formula used in a case involving The Southern New England Telephone Company (SNET) with selected elements of the Pole Attachment Order's revised upper bound Telecom formula resulting in an inflated annual pole rental rate. As such, CL&P's pole rate methodology deviates from the Pole Attachment Order by not using the FCC's lower bound Telecom Formula, which excludes capital costs from the cost of providing space, since those costs are recovered through make-ready. The lower bound formula is intended to ensure that pole owners are fully compensated for actual costs associated with pole attachments. Id.

NECTA also argued that CL&P deviated from the Pole Attachment Order methodology as follows:

1. The Pole Attachment Order methodology uses historic (embedded) costs while CL&P uses a combination of historic and reproduction (marginal) costs, which the FCC has expressly rejected;

2. The Pole Attachment Order methodology applies cost allocators of 66% in urban areas and 44% in rural areas while CL&P applies higher cost allocators of 69.18% in urban areas and 45.38% in rural areas; and

3. The Pole Attachment Order methodology allocates pole costs using a presumption of 13.5' of usable space on the pole to derive a space allocation factor while CL&P uses 12.33' without providing credible evidence to rebut the 13.5 feet usable space presumption.

NECTA did not dispute the basic formula used by CL&P used in its calculation, but rather, the assumptions. NECTA outlined the Pole Attachment Order formulas is as follows:

- FCC Pole Attachment Order formula (for Cable) = Net Pole Cost x Carrying Charge Factor x Space Allocation Factor

- FCC Pole Attachment Order formula (for Telecom) = Net Pole Cost x Carrying Charge Factor x Space Allocation Factor x Conversion Factor

Id.

NECTA contended that the average pole height and average amount of usable space on the pole (pole height above ground clearance) has increased. NECTA members, including Cablevision, Charter, Comcast, Cox, and MetroCast, conducted a survey of current pole plant under the direction of NECTA and a statistician, Dr. Charles Cowan, with Analytic Focus (Pole Survey). The Pole Survey used a sample population of approximately 500 poles. The data collected included the pole height and the height of the lowest strand on the pole attached with a through bolt for each sampled pole. The data was then extrapolated back into the total universe of CL&P poles to obtain the average pole height and the average amount of usable space on the pole. According to the study, the average CL&P pole height is 38.57'. Removing 18' clearance and 6' setting depth, the remaining space usable for pole attachments is 14.57', greater than the 13.5' presumption in the Pole Attachment Order and the 12.33' assumption used by CL&P. Id., pp. 5-12; Cowan PFT, pp. 1-5.

In summary, NECTA argued that CL&P calculated a sizable CATV Rate increase and a Telecom Rate that does not meet the Pole Attachment Order methodology. NECTA stated that proper application of the FCC Pole Attachment Order formulas produce solely-owned CATV Rates of $14.33 for cable, and solely-owned Telecom Rates of $14.30 in urban areas, and $14.38 in rural areas. Exhibit PG-2. If any presumptions are changed they should reflect the data collected by NECTA member operators supporting an average pole height of 38.57' and a usable space factor of 14.57'.

c. Position of the Parties

The OCC agreed with NECTA, stating that CL&P has failed to calculate its rates in conformance with the Pole Attachment Order as ordered in the Fibertech Decision. The Company's methodology incorrectly incorporates a rate-setting methodology

derived from a PURA order from the 1993 SNET Rate Case. The Fibertech Decision followed the methodology detailed in the Pole Attachment Order, and directed calculations that superseded the SNET 1993 Rate Case Decision. OCC Brief, pp. 133 and 134.

d. Authority Analysis

The Authority agrees that CL&P's proposed pole attachment rates do not conform with the Pole Attachment Order or the Authority's prior directives. In calculating either rate, marginal costs should not be used in calculating the net pole cost. The use of 100% embedded costs is both consistent with the directives of the Pole Attachment Order and other FCC decisions as well as the methodology contemplated by the Authority in the Fibertech Decision. Therefore, the Authority approves the use of the fully embedded net cost of $609.62 in the pole attachment rate calculation. Further, the Authority finds NECTA's proposed average pole height of 37.57', usable space factor of 14.57' and unusable space factor of 24' from the Pole Survey are acceptable for use in calculating rates in this case. The Company will be directed to conduct a usable space survey prior to filing its next rate case. The Authority will use CL&P's proposed conversion factor, adjusted from 31.73% down to 31.54%, to reflect the allowed ROE of 9.02%. Lastly the conversion factors used by CL&P in calculating the Telecom Rate do not conform to the conversion factors outlined in the Pole Attachment Order (66% of the fully allocated costs for urban and 44% for rural) and will be adjusted by the Authority.

Based on the above, the Authority recalculates the CATV and Telecom Rates as shown:

Table 79

CATV Formula						
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate
	=	6.86%	x	$609.62	x	31.54%
		Fully Owned		Jointly Owned*		
	=	**$13.19**		**$6.60**		
* Fully Owned Rate / 2						

Table 80

Telecom Formula								
Maximum Rate	=	Space Factor	x	Net Cost of a Bare Pole	x	Carrying Charge Rate	x	Conversion Factor
Maximum Rate (Urban)	=	10.889%	x	$609.62	x	31.54%	x	66.00%
		Fully Owned		Jointly Owned*				
		$13.82		**$6.91**				
Maximum Rate (Non-Urban)	=	16.420%	x	$609.62	x	31.54%	x	44.00%
		Fully Owned		Jointly Owned*				
		$13.89		**$6.94**				
* Fully Owned Rate / 2								

The Authority approves the Company's proposal to flow variations in pole attachment revenue through the decoupling mechanism, and to provide prorated bill adjustments for December 2014.

7. Unbundling of Street Lighting Rates

a. Existing Street Lighting Rate Design

In the 2009 CL&P Rate Case Decision the Authority approved the unbundling of street lighting rates into their functional components (e.g., Distribution, Transmission and Generation Service). Based on that ruling, the Company proposed an unbundled rate design of street lighting service and set pricing for: (a) the component of service associated with the use of the distribution system that would apply to all street lighting customers, regardless of street light facilities ownership (i.e., the "system" component of rates); and (b) the component of service associated with Company-owned street lighting facilities applicable only to CL&P's full service street lighting customers [e.g., the equipment and operations and maintenance (O&M) components of rates]. The Company stated that a rate structure based on this unbundling is critical to its ability to introduce a Company-owned light-emitting diode (LED) street lighting option that has a cost basis consistent with other traditional street lighting technology options.

CL&P stated that its proposal shows the actual cost of providing these services. It used that data along with other factors to develop a street lighting rate design that better reflects the Company's cost of service. Davis PFT, pp. 14 and 15. The following Table shows the distribution breakout by component:

Table 81

STREET LIGHTING DISTRIBUTION RATE DESIGN				
Distribution Breakout by Component				
Rate Year Ending 2015	Rate 117		Rate 116	
Fixtures	A	46,289	E	141,898
Connected Demand KW	B	5,659	F	22,540
Annual kWh	C	23,425,448	G	92,563,009
Proposed Distribution Revenue	D	$839,496	H	$16,894,406
Distribution by Category				
1) D - System Demand				
Revenue $	I = D * 75%	$629,622	K = J* F* 12* 1000	$2,507,700
Charge Per Watt	J = I / B	**0.00927**	L = K / F	**0.00927**
2) D - System Customer				
Revenue $	M = D * 25%	$209,874	O = N* E* 12* 1000	$643,365
Charge Per Fixture	N = M / A	**$0.38**	P = O / E	**$0.38**
3) D - Operations & Maintenance				
Revenue $			Q = RY COSS O&M	$2,574,000
Charge Per Fixture			R = Q / E	**$1.51**
4) D - Equipment				
Revenue $			S = H- K- O- Q	$11,169,342
Total D		**$839,496**		**$16,894,406**

Exhibit EAD-8, p. 1.

The Company proposed a two-part charge for Partial Street Lighting Service (Rate 117) consisting of customer and demand components that applies to applicable fixtures connected to the CL&P's distribution system. The customer component is a uniform rate per fixture that applies monthly to each fixture connected to the Company's system. The demand component is a uniform rate per watt that applies to the rated wattage of each fixture under either rate schedule. These two charges are combined to form the total charge per fixture each month for the system component of distribution service. The revenue targets for customer and demand were derived by applying a 75% / 25% proportion of demand and customer costs, respectively, to the proposed distribution revenue (D). Accordingly, for each fixture the monthly distribution charge under Rate 117 would be $0.38 plus the product of $.00927/watt and the wattage of that fixture. These would be the only distribution charges for service under Rate 117, and also become the system-related distribution charges for Street and Security Lighting (Rate 116). CL&P contended that the proposed rate design appropriately charges all street lighting fixtures the same formula distribution rate for the use of the system, regardless of wattage and regardless of equipment ownership.

For Rate 116, additional equipment and O&M charges apply. The street lighting O&M rate is an average monthly rate that applies uniformly to all Rate 116 fixtures. This rate, which equals $1.51 per fixture, has been derived directly from street lighting O&M expenses of the COSS shown on page 2 of Exhibit EAD-8. The monthly equipment charge was developed for each specific type of equipment utilized by customers taking service under Rate 116. CL&P developed these charges by calculating the total installed cost of each type of equipment and developing a monthly

rate by multiplying a street lighting carrying charge by the installed cost of each type of street lighting equipment. The Company proportionally adjusted the calculated equipment charges by a factor of 1.054 (the ratio of the $11.2 million equipment revenue requirement to the $10.6 million calculated equipment revenue) to derive proposed equipment prices. Davis PFT, pp. 13-19; Exhibit EAD-8, p. 3.

b. New Street Lighting Options

The Company proposed to introduce several new street and highway lighting options that utilize LED technology. The unbundling and development of rates for the system, equipment and O&M components of street lighting service discussed above provide a structure upon which the Company has been able to develop LED rates. The same methodologies for determining the system, equipment and O&M rates for other street lighting service offerings has been applied in developing proposed LED street lighting distribution rates. Davis PFT, pp. 13-19; Exhibit EAD-8.

The Authority accepts CL&P's proposed unbundled rate design methodology for Rates 116 and 117. The proposed rate design effectively carves out the equipment costs from the general distribution system costs and allocates the equipment costs to customers in a manner that is more cost-based than the previously bundled rates. The Company will be directed to adjust the proposed rates to reflect the new revenue targets shown in Section II.J.4, Revenue Allocation.

8. Tariff Changes

a. Company Proposals

The Company proposed to update certain provisions in its rate schedules and terms and conditions (T&Cs) for service and to update charges for a number of services provided under the T&Cs. The Company also proposed to withdraw its surge protection tariff as previously approved by the Authority; proposed tariff language to implement the unbundling of street lighting offerings, as discussed in Section II.J.7, Unbundling of Street Lighting Rates; and proposed a new TOD rate for residential heating customers on Rate 5.

i. Terms and Conditions for Electric Suppliers

The Company's proposed amendments to the T&Cs for Electric Suppliers included several proposed new definitions and clarifying provisions associated with changes in market-related services, obligations and practices (e.g., supplier switching rules), and elimination and proposed changes to fee structures for data and information services. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

ii. Terms and Conditions for Delivery Service

The Company's proposed amendments to the T&C's for Delivery Service included clarifying changes to definitional terms and labeling, and several new provisions including unauthorized use and meter diversion. These T&C amendments included a proposed new meter diversion fee, proposed changes to the reconnection

fee structure and rates, and proposed, restructured extended metering options. The proposed rates for these services have been developed based on the cost of providing service under these options. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

iii. Withdrawal of Surge Protection Tariff

The Company requested approval to withdraw its surge protection tariff, pursuant to a previous letter order ruling by the Authority approving the CL&P's request to discontinue this program.[51] Also, a new Metering Communications Equipment provision is proposed to replace the Telemetering provision (or to be added where such provision is not currently stated) for any schedule that has meter communications requirements associated with electric service meters. The Company also proposed clarifying language regarding the availability and applicability provisions associated with small commercial rates (Rates 27, 30, 35 and 37), and with regard to the billing of certain charges under the Company's net metering tariffs. Davis PFT, pp. 24 and 25, Exhibit EAD-11.

iv. Residential Heating Time-of-day Rate

Currently, CL&P offers a TOD rate option, Rate 7, for residential non-heating customers. Rate 7 was designed based on the service characteristics of the non-heating residential class, Rate 1, and on methodologies and guidelines developed and approved by the Authority that resulted in time-differentiated generation service rates and an overall rate design conducive to the migration of Rate 1 customers to Rate 7 TOD service. Because residential heating customers do not have a comparable TOD option, the Company developed a new TOD rate, Rate 6, based on the specific service characteristics of Rate 5 and application of the same methodologies and guidelines used in developing Rate 7. Davis PFT, pp. 19 and 20.

The general availability, applicability and other provisions of Rate 6 are identical to those of Rate 5, with the exception that Rate 6 is open to new customers. As in the Rate 7 rate design, the non-TOD rate components of Rate 6, including the customer charge and per kWh charges, are the same as those for Rate 5. The generation service charge however, has been developed on a TOD basis using the same differential between peak and off-peak rates as used in designing Rate 7 pricing. This differential has been applied on a revenue neutral basis to develop the TOD equivalent of the Rate 5 generation service charge and thereby provide a TOD rate option specifically for Rate 5 customers. Id., Exhibits EAD-11 and EAD-12.

b. Position of the Parties

The BETP generally supported time-of-use rates; however, it suggests that CL&P educate customers on the benefits of time-of-use rates and improve the structure of its existing time-of-use rates rather than add another new residential rate. The BETP also suggested that CL&P redesign its Residential Time-of-Use Rate 7 and focus on

[51] See, March 20, 2014 letter order ruling on Motion No. 54 in Docket No. 09-12-05.

educating customers on the value of time-of-use rates rather than create a new and unnecessary time-of-use rate. It is unclear why CL&P is proposing a new time-of-use rate option other than to have a rate that directly corresponds to Rate 5 residential heating. The rate design and resulting bills for Rate 6 are very similar to those on Rate 7, which is already available to Rate 5 customers. Rate 7 however, has not been successful in attracting customers from Rate 1 or Rate 5. Less than 500 customers receive service on Rate 7 compared to over 1.1 million customers on Rate 1 and Rate 5. The BETP commented that CL&P has done little to educate customers and promote time-of-use rates in the past and does not have a plan to do so in the future. BETP Brief, pp. 14 and 15.

c. Authority Analysis

The Authority denies the Company's proposed implementation of the proposed Rate 6 as a TOD companion tariff to Rate 5. Rate 5 is a legacy tariff and new customers are no longer allowed to take service under that rate. It seems counterintuitive to allow new customers to take service under a companion tariff to Rate 5. However, the existing TOD Rate 7 should continue to be made available to Rate 5 as well as Rate 1 customers. Since both the customer and the volumetric delivery charges under Rate 7 will be lower than Rate 5, customers will still realize a benefit on the distribution portion of their bill as well as the differential between peak and off-peak rates in the generation services charge. It remains uncertain as to how much of an incentive will be necessary to drive significant migrations to TOD rates for any type residential customer. This is evident by the lack of participation in Rate 7, and the anticipated low migration rates the Company expects for Rate 6. CL&P Response to Interrogatory RA-22. Further, it is unclear whether a similar pricing mechanism would be the right fit for a heating customer's service characteristics. The Authority welcomes more discussion on this matter and how the current residential TOD tariffs could be redesigned to stimulate more customer participation.

The Authority finds it appropriate, given the increase to distribution rates herein, to require that CL&P increase the charge for reconnection at the meter from $35 to $42, instead of the Company's proposal to lower that charge to $31. This rate has not changed in many years, despite increases to general rates.

The Authority accepts the Company's remaining proposed tariff changes subject to rate amendments pending Authority approval of final rates as directed in Section II.J.5, Rate Design. Regarding the availability sections of Rates 27, 30, 35 and 37, the Authority approves the Company's proposed minimum demand requirement of 200 KW under which customers are not eligible to return to Rate 30 or Rate 35.[52] The Authority approves the proposed revisions to Rates 116 and 117 with the associated charges subject to change pending the reallocation and rate design of the approved revenue requirements herein.

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[52] The Authority previously ordered that it be lowered to 100 kW in a three-phase implementation process in the Decision dated December 21, 2006 in Docket No. 05-10-03, Application of The Connecticut Light and Power Company to Implement Time-of-Use, Interruptible or Load Response, and Seasonal Rates. By Decision dated May 10, 2010 in that Docket, the Authority delayed the implementation of the final phase of Order No. 7.

K. NEW BUSINESS POLICIES

CL&P's New Business Policies (NBP) establish standardized costs and methodologies for developing work estimates and for billing customers those costs that are customer-specific which are not recovered in rates. CL&P submitted revisions to its NBP in this proceeding. Bowes PFT, Exhibit KBB-5.

CL&P's NBP revisions primarily reflect organizational changes that have taken place since the Company's last revisions in 2011. The revisions also update certain prices to current costs, and update metering technology and requirements to current standards, which have evolved over time, particularly with regard to distributed generation interconnections and communication technology. No party or intervenor opposed the Company's NBP revisions.

The Authority finds that the NBP revisions are reasonable and appropriate. The Authority therefore approves the revisions to the NBPs.

L. CUSTOMER SERVICE ISSUES

1. Customer Notifications and Collections

CL&P's standard bill form, termination notice and customer rights notice were reviewed and found to be in compliance with applicable regulations. Application, Schedule H-2.0, Exhibits A and B; Response to Interrogatory CA-7. CL&P's Terms and Conditions for Delivery Service were also reviewed and found to be in compliance with applicable regulations. Application, Schedule H-2.0, Exhibit E, Schedule E-1.0 and E-1.1; Response to Interrogatory CA-19.

The Company implemented a strategy in 2010, to more effectively manage and pursue collections on inactive customer accounts, and modified the plan for efficiency in the following three years. CL&P then summarized the results of its changes in workflow timing for collections efforts in relation to final bills, and indicated a noticeable increase in its collection of outstanding revenues. Response to Interrogatory CA-5. The Company measures its "net back," which is the total collections made on its behalf, minus the commissions that CL&P pays to the collections agency. The Company's Net Recovery percentage increased from 0% to 7.1% between 2010 and June 2014. Id.; Tr. 8/27/14, pp. 61 and 62. The total number of accounts in arrears increased 12% from 114,808 in June 2011 to 128,595 in June 2014. However, the total amount of arrearages increased only 1.3%, from $76.5 million to $77.5 million, during the same period. Response to Interrogatory CA-21.

2. Policy and Procedures for Estimated Billing

CL&P provided its policy and procedures for generating an estimated bill. CL&P's billing system produces an estimated bill based upon historical usage in the comparable month in the prior year. The Company continues to follow the automated notification process to inform customers of options to avoid an estimated bill as outlined

in Order No. 20 in the 2009 CL&P Rate Case Decision. Response to Interrogatory CA-1.

CL&P issues estimated bills infrequently. The table below shows the percentage of estimated bills issued over time periods ranging from one month to 12 or more months:

Table 82

Year	1 Month	2-3 Months	4-6 Months	7-11 Months	12+ Months
2014 Y-T-D	1.487%	0.263%	0.073%	0.003%	0.000%
2013	2.760%	0.518%	0.127%	0.041%	0.001%
2012	1.275%	0.542%	0.138%	0.012%	0.000%
2011	3.298%	0.703%	0.201%	0.017%	0.000%

Response to Interrogatory CA-13.

The Authority finds the extremely low percentage of estimated bills issued by the Company supports CL&P's current estimated billing policy and procedures. The Company's estimated billing procedures have been reviewed and found to be in compliance with applicable regulations. CL&P's bill form and associated customer notices were also reviewed and found compliant. Application, Exhibit H-2.0, Exhibit D.

3. Customer Security Deposits

The Authority has reviewed CL&P's current customer security deposits policies and procedures and found them to be in compliance with Conn. Agencies Regs. §16-11-105 and §16-262-1. Application, Schedule H-2.0 Exhibit F, Customer Service Policies, No. C150.1 and No. C350.1; Response to Interrogatory CA-18. The Company provides policy and procedures in writing to those customers that are required to pay a security deposit, and stated that there are other means by which customers are informed of security deposit requirements. For example, termination notices inform the customer that a security deposit may be required before service can be restored, and CL&P's Customer Service Representatives remind customers that a deposit is required when reinstating service. Finally, new commercial accounts receive information in the mail regarding security deposit requirements and how they are calculated. Response to Interrogatory CA-18.

4. Energy Audit Service Appointments

In October 2012, CL&P informed the Authority of its intent to discontinue the practice of on-site energy audit service appointments at a customer's location by Energy Service Representatives. Docket No. 09-12-05, Order No. 19 compliance filing dated October 3, 2012. The new customer service practice is to guide customers to more comprehensive energy savings programs such as the Connecticut Energy Efficiency Fund's Home Energy Solutions. The Company maintains that these programs are a cost-effective way to provide customers with maximum energy and dollar savings. Id. After completing its own review of the Company's policy change as described above, the Authority approved the change in November 2012. PURA Response to Docket No. 09-12-05, Order No. 19 compliance filing dated November 2, 2012.

5. NUStart Program

CL&P changed its NUStart program in 2013, shortening it from a three-year program to a one-year program, because customers were routinely failing to maintain required budget payments over a 36-month period, and thus placed back in the service disconnection stream. By converting NUStart to a one-year program, an increased amount of forgiveness dollars is applied to NUStart balances, which helps reduce arrearages at a quicker pace. From 2010 to 2012, only 1,543 customers completed the NUStart program. After the program change was made in 2013, approximately 6,000 customers successfully completed the program. In the first six months of 2014, 2,347 customers successfully completed the NUStart program. NUStart program changes have dramatically increased participants' success. Response to Interrogatory CA-15.

6. Customer Call Center

CL&P maintains a Customer Service Center to address customer complaints and inquiries. Statistics below, submitted by CL&P for calendar years 2012 through 2014, depict the call center's monthly performance:

Table 83

2012	ASA[53]	ACR[54]	2013	ASA	ACR	2014	ASA	ACR
January	31.5	2.6%	January	15.9	1.3%	January	60.2	5.3%
February	35.3	2.8%	February	20.7	1.8%	February	38.7	3.4%
March	29.9	2.7%	March	14.4	1.1%	March	20.4	1.9%
April	51.4	3.9%	April	23.0	1.2%	April	6.1	1.1%
May	25.5	2.2%	May	24.7	1.9%	May	12.9	1.5%
June	10.8	1.3%	June	25.2	2.5%	June	9.6	1.4%
July	12.8	1.8%	July	27.5	2.4%	July[55]	12.0	1.8%
August	10.7	1.4%	August	26.0	2.2%	-------	------	-------
September	18.8	1.8%	September	27.3	2.7%	-------	------	-------
October	13.9	1.4%	October	7.4	1.1%	-------	------	-------
November	14.2	1.5%	November	15.7	1.9%	-------	------	-------
December	17.3	1.8%	December	8.7	1.4%	-------	------	-------

Response to Interrogatory CA-2.

Currently, there are no specific standards or benchmarks for electric distribution company call center metrics set forth in Connecticut's state statutes or regulations. The Authority finds CL&P's call center performance statistics to be acceptable as filed, based upon its experience in reviewing other regulated utilities call center statistics. Response to Interrogatory CA-2.

CL&P participates in monthly meetings with the Authority's Consumer Affairs Unit as a means to improve upon the level of service provided to customers. These monthly meetings were established in the 2009 CL&P Rate Case Decision, Order No. 30. All parties agree that these meetings have been helpful in handling customer service matters and the parties mutually agree it will be beneficial to continue meeting each month.

7. Conclusion

Overall, the Authority finds CL&P's customer service policies and procedures to be in compliance with applicable statutes and regulations.

III. FINDINGS OF FACT

1. The ADIT for the Test Year ending December 31, 2013 is $655.417 million.

2. The plant related non-FAS 109 ADITs were $461.429 million, $553.453 million, $567.297 million, $674.02 million, and $658.815 million for calendar years ending December 31 in 2009, 2010, 2011, 2012 and 2013, respectively.

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53 Average Speed of Answer, in seconds.

54 Abandoned Call Rate.

55 Through July 13, 2014.

3. The deferred tax liability created by the permanent RTD regulations will reverse over the same time period as the related assets capitalized in accounting books are depreciated.

4. RTD treatment is the same as that of other normalized deductions for tax and regulatory purposes.

5. CL&P included normalized ADITs of $40.85 million in 2014 and in 2015 for RTD.

6. The 2014 and 2015 levels of ADITs are based on RTD allowances of $100 million in each year.

7. CL&P did not adopt the RTD temporary regulations.

8. CL&P will adopt the final RTD regulations and include benefit associated with RTD deductions for 2012 and 2013 in its 2014 tax returns.

9. There are additional look-back periods for which costs incurred for repair and maintenance of tangible property can be deducted in the 2014 tax return with the adoption of the final RTD regulations.

10. CL&P failed to incorporate additional deferred tax benefits for the RTD look-back periods, which included 2012 and 2013, in its estimated deferred taxes for 2014.

11. CL&P will be included in that cumulative adjustment in its 2014 tax return, amounts which would have been deducted in 2012 and 2013.

12. The Company will record additional normalization deferred tax liabilities for the 2012 and 2013 RTD allowances in its books.

13. The Company only included the deferred taxes associated with RTD allowances in 2014 and 2015 in this proceeding.

14. The Company reduced the ADITs balance Account 28200 by $124,742,248 in August 2013.

15. The $124,742,248 reduction represents a subsequent true-up of estimates made during 2012 based on adjustment in its 2012 tax return.

16. A shorter retirement schedule increases the deduction for depreciation expense for a particular period.

17. Businesses may automatically change from one permissible method of computing depreciation expense for tax purposes to another permissible method by filing Form 3115.

18. Recent tax law changes allow corporations special tax deductions, above the normal MACRS amounts.

19. Account 282 is debited and Account 411 is credited with an amount by which income tax is greater due to tax/book differences from prior years.

20. The net changes to the balances in Account 28200 are $95.888 million in 2011, $100.262 million in 2012 and ($42.293) million in 2013.

21. The annual accretions to the ADITs balances in Account 28200, exclusive of true-up adjustments, are $95.888 million in 2011, $101.330 million in 2012 and $82.449 in 2013.

22. The total federal depreciation deductions are $541,275,640 in 2011 and $586,677,407 in 2012.

23. The distribution portions of total federal tax depreciation deductions are $359,956,682 in 2011 and $384,142,472 in 2012.

24. No adjustments were made to the balance in Account 28200 in August 2011 and a reduction of $1.1 million in August 2012.

25. On August 1, 2013, the Company submitted to the Authority a compliance filing that included a Form 3115 filed with the IRS.

26. In the Form 3115 filed on July 10, 2013, CL&P requested an automatic change of its method for accounting for certain retirement costs.

27. The amount changed from NOL was $19.939 million in 2011 to $118.004 million in 2012.

28. The total system resiliency plant addition in 2013 was $25.554 million.

29. The book depreciation related to total system resiliency plant addition in 2013 was $198,000.

30. The ADIT associated with the total 2013 system resiliency plant addition was $252,000.

31. CL&P used a stratified random sample of its retail accounts and calculated that it took an average of 40.95 days for CL&P to receive its revenues once service has been rendered based on data through December 31, 2013.

32. Included in this average revenue lag of 40.95 days is a service lag (time between service being provided and the reading of the meter) of roughly 15 to 16 days, a billing lag (time between the reading of the meter and sending out the bill) of two to three days and a payment lag (time between the bill being sent out and the payment being received by the Company) of approximately 23 days (41 days minus 15 days minus 3 days).

33. The Company calculated a cash working capital requirement of $17,230,000 based on a net lag of approximately 3.20 days for the Rate Year.

34. The OCC argued that non-cash expenses should not be part of the lead/lag study because they do not involve an outlay of cash and are excluded by some regulatory jurisdictions in the determination of a working capital allowance.

35. If there is a lag between a reduction in rate base resulting from an expense and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag.

36. The lead/lag study proposed by the Company assumes and/or calculates that depreciation expense (and expense related to amortization and deferred taxes) results in a reduction to rate base after 15 days on average and that funds for this expense are received 25.95 days later.

37. A service lag is appropriate for revenues associated with most expense categories, but not appropriate for revenues associated with costs recovered through adjustment clauses that use billed revenues.

38. Based on billing cycles of 27 to 33 days and 12 months in a year, a reasonable estimate of the service lag would be 15.21 days.

39. The Company identified three of its adjustment clauses as using billed revenues to recover costs; the CTA, the SBC and the NBFMCC. These clauses recover $30,860,000, $41,418,000 and $189,702,000 in Rate Year costs, respectively.

40. The expense and income levels used to calculate the working capital needs of the Company reflect the expense and income adjustments made by this Decision.

41. The Traditional Capital Program consists of expenditures for programs that address routine infrastructure issues such as those necessary to supply new customer loads, meet peak loads, meet basic business requirements, meet regulatory commitments, and reliability related projects.

42. The Pre-Approved Resiliency Plan consists of system resiliency expenditures for programs that were approved in the Resiliency Decision.

43. The New System Resiliency Programs are for system resiliency measures that were not approved in the Resiliency Decision.

44. CL&P proposed to spend $257 million on its Traditional Capital Program in the Rate Year.

45. The Authority previously examined the issue of plant in service forecasting in its Decision in Docket No. 05-07-04.

46. Total CL&P capital spending over the years 2010-2012 was $958.8 million, which was within 0.2% of its forecast.

47. CL&P planned to spend $44 million on its New Resiliency Programs in 2015.

48. In the 2013 Study, CL&P used a depreciation system composed of the straight line method, ASL procedure, and remaining life technique.

49. CL&P last filed a Depreciation Study based on plant as of December 31, 2008.

50. The Company originally requested a Rate Year payroll expense of $135.881 million.

51. The Company revised the requested Rate Year payroll expense to $135.198 million.

52. The Company's requested level of FTE positions is 4,435.8 for the Rate Year.

53. Since the merger in April 2012, staffing levels have been reduced.

54. As of August 31, 2014, the Company had 4,235.8 FTEs.

55. From December 31, 2013 through August 31, 2014, 201 positions became vacant due to attrition.

56. Of the 201 open positions, CL&P is actively seeking to fill 101..

57. Of the remaining 100 positions, 68 are for CL&P and 32 are for NUSCO.

58. As of September 5, 2014, the Company had 82 of the 101 positions still active and open.

59. The remaining 100 positions are at various stages of review in the Company's Human Resources organization and within the businesses.

60. The Company used a benefits loader of 46.2% and a payroll taxes loader of 8.5%.

61. CL&P has a defined benefit pension plan that covers the majority of its existing employees.

62. In 2006, CL&P closed entry to its defined pension benefit plan to newly hired non-bargaining employees.

63. On January 1, 2006, the Company introduced a new enhanced 401(k) based benefit called the K-Vantage Program for all new non-union hires and allowed existing employees to opt out with their pension frozen into the new benefit program.

64. All new employees participate in the K-Vantage benefit instead of a defined benefit plan.

65. The Company offers retiree health care benefits for all retired employees.

66. The pension expense was calculated on the basis of the accounting rules set forth in ASC 715-30.

67. Pension service cost is the increase in projected benefit obligation due to the accrual of benefits that occurred in the current period.

68. Pension interest cost reflects the growth in present value of projected accrued benefit obligations as they come one period closer to payment.

69. CL&P's pension Test Year expense was $47,213,000.

70. For pension expense, CL&P requested $27,736,000 in the pro forma rate year of 2015.

71. The OPEB expense is calculated on the basis of the accounting rules set forth in ASC 715-60.

72. The health care cost trend rate represents the expected annual rates of change in the cost of health care benefits currently provided by the post-retirement health care benefit plan.

73. CL&P's OPEB Test Year expense was $7,771,000.

74. For OPEB expense, CL&P requested $4,061,000 in the Rate Year.

75. CL&P capped health care subsidies and changed plan designs for both pre-65 retirees and post-65 Medicare eligible retirees.

76. The portion of post-retirement health care expense associated with capped benefits has grown to 85% as of December 31, 2013.

77. CL&P transitioned pre-65 retirees to the same medical designs offered to active employees in 2013.

78. In 2013, CL&P introduced a Medicare Part D employer group waiver plan through its pharmacy benefits manager.

79. CL&P retiree participation in the employer group waiver plan provides lower cost as a result of offsetting payments from Medicare in the form of Part D direct subsidy payments, low income subsidies, pharmacy manufacturer reimbursements, and catastrophic reinsurance payments.

80. In 2014, the Company updated the plan design for Medicare eligible retirees which eliminated non-Medicare coverage and applies the full Medicare Part B deductible on all participants.

81. In 2007, CL&P implemented a Med-Vantage that supplements benefits offered to employees in K-Vantage.

82. The key actuarial assumptions used in determining the Company's pension and OPEB expense are: 1) discount rate, 2) expected return on assets, 3) average wage increase, and 4) health care cost trend rate.

83. The discount rate is used to evaluate the present value of the plan liabilities.

84. The higher the discount rate, the lower the present value resulting in lower pension and OPEB expense.

85. Expected return on plan assets is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix.

86. The higher the return on plan asset assumption, the more the plan assumes it can earn resulting in lower pension and OPEB expense.

87. The average wage increase is the assumed increase in annual wages for all employees in the plan.

88. The higher the average wage increase assumption, the higher the pension expense.

89. The health care cost trend rate is comprised of an initial and ultimate cost trend rates which is an estimate of future health care costs.

90. The higher the health care cost trend rates, the higher the OPEB costs.

91. The health care cost trend rate applies only to the OPEB Plan.

92. The SEC requires the use of high quality bond yields to calculate the discount rate.

93. CL&P used a discount rate of 4.26% as an input to calculate pension expense and a discount rate of 4.07% to calculate OPEB expense.

94. CL&P used input from actuaries, consultants, and economists to develop the expected long-term rate of return assumption of 8.25%, for both the pension and OPEB plans.

95. Data inputs for the expected long-term rate of return assumption are derived from long-term inflation and growth statistics for the economy.

96. The Company used an average wage increase assumption of 3.50% in its actuarial calculations.

97. There are two assumptions composing the healthcare cost trend rate: the initial assumption and the ultimate assumption.

98. The initial healthcare cost trend rate assumption reflects expectations of health care cost increases for retirees in the near term. It is based on a number of factors including publically available general industry surveys, actual experience of the Company's retiree population, and experience of other large clients with post-retirement health care plans.

99. The ultimate healthcare cost trend rate assumption is developed from a building block methodology. It is established to reflect improvement in technology and additional utilization.

100. The assumptions used in the valuation of the initial and ultimate health care trend rates are evaluated against those used by other general and utilities industry companies to ensure comparability.

101. CL&P used an initial health care cost trend rate of 6.75% with an ultimate rate of 4.50% for the calculation of the OPEB expense.

102. A 401(k) plan is a qualified retirement plan under the Internal Revenue Code that allows employees to save a portion of their salary for retirement on a pre-tax basis.

103. In a 401(k) employers match a portion of each employee's contribution with the employee choosing the investment options for the contributions.

104. By the end of the Test Year of 2013, approximately 30% of CL&P and NUSCO employees were participating in K-Vantage as compared to less than 20% in 2009.

105. A SERP is a non-qualified plan that provides executives with a supplemental retirement benefit in addition to the benefit provided under the qualified plan.

106. There are 34 current employees eligible for SERP benefits when they retire.

107. There are 51 retired employees and/or spouses currently collecting SERP benefits.

108. There will be no new participants in the SERP because CL&P no longer offers a defined benefit pension plan to new employees.

109. CL&P's SERP complies with section 409A of the IRS Code.

110. CL&P's Test Year SERP expense ending December 31, 2013, was $1,680,000.

111. For SERP expense, CL&P requested $2,039,000 million in the pro forma rate year of 2015.

112. The Non-SERP account is used to record expenses related to specially negotiated post-employment benefits, including pension enhancements not covered by the NUSCO Retirement Plan or the SERP.

113. Non-SERP enhancements are normally provided in the hiring agreements to make up for benefits lost at previous employers by some mid-career hires or as part of a separation agreement with NU.

114. CL&P provided a Non-SERP benefit to one employee that was hired after January 1, 2006, but excluded that expense in the rate year.

115. The Authority allowed the Non-SERP benefit in the 2007 Rate Case.

116. Allocations from NUSCO are made through direct charges to the operating company that benefitted from the charge whenever possible.

117. NNECO was the agent for Northeast Utilities system companies and other New England utilities in operating and maintaining the Millstone Nuclear Generation facilities.

118. In the 2009 CL&P Rate Case, CL&P was allowed recovery of 81% of NNECO pension costs in rates.

119. CL&P's pension expense projections included costs being allocated to CL&P distribution operations from NNECO.

120. CL&P capitalized a portion of its pensions and OPEB expenses into rate base.

121. When employees are doing capital work, a portion of their benefits and pension costs are capitalized with their direct labor costs.

122. The amount of pension expense that is capitalized is based on the payroll that is capitalized.

123. The actual capitalization amounts recorded on the Company's books reflect an allocation of employee benefits, payroll taxes and insurance to expense and capital consistent with how payroll was distributed and recorded in the Test Year.

124. CL&P requested $310,000 for consulting/actuarial fees on Schedule C-3.27 for both the Test Year and the Rate Year.

125. CL&P consultant and actuarial fees have been trending downward since 2010.

126. The Company requested $1.5 million for rate case expense associated with this proceeding.

127. The Company proposed the rate case expense be amortized over seven years.

128. The proposed $1.5 million rate case expense includes $100,000 for an ROE witness; $350,000 for a depreciation witness; $500,000 for legal expenses; $300,000 for OCC consultants; $100,000 for other external costs and $150,000 for incremental costs.

129. The projected Rate Year rate case expense is 611% higher than the previous rate case.

130. The Company recovered the 2009 CL&P Rate Case expense in one year.

131. The Authority typically allows amortization periods of three to five years.

132. Residual O&M expense represents the portion of Test Year expenses that CL&P specifically did not analyze based on the size of the dollar amounts involved.

133. CL&P revised its residual O&M expense request due to an accounting error.

134. For the Test Year ended December 31, 2013, CL&P subtracted total expenses excluding residual of $379,216,000 from total Test Year O&M expense of $381,729,000 for a Test Year residual O&M Expense of $2,513,000.

135. A Test Year pro forma adjustment of $2,122,000 and a Rate Year pro forma expense of $4,635,000 were made.

136. Test Year total operating expenses were charged to over 500 accounts and sub-accounts.

137. For CL&P Distribution and NUSCO, costs allocated to CL&P Distribution Test Year expenses were broken down into CCC levels by direct costs.

138. In April 2013, The State of Connecticut reimbursed CL&P in the amount of $2,553,000 for an overpayment of the State Economic Recovery Reduction Bonds.

139. CL&P made an accounting adjustment correction of $1,442,000 for storm costs.

140. In December 2013, CL&P Distribution Company recorded $106,000 in payments in error as a residual O&M expense which was corrected in January 2014.

141. The $4,635,000 million rate year request of residual O&M expense does not reflect an inflation factor.

142. CL&P removed Account No. 90500, Miscellaneous Customer Account Expense, of $143,167 from residual O&M expenses.

143. CL&P removed Account No. 921105, Office Expense Building, of $63,819 from residual O&M expenses.

144. The Company reported that $106,000 was incorrectly charged to CL&P for the low income special needs program payable to the Boathouse Group in December 2013.

145. CL&P reflected an $119,000 decrease in officer's expense from its residual O&M request.

146. CL&P reflected a $207,000 decrease in miscellaneous costs from its residual O&M request.

147. The Company included $583,000 in its Application for BOD expense.

148. The main objective of the BOD is to protect the interest of the Company's shareholders.

149. Ratepayers may indirectly benefit from the activities of the BOD.

150. In the past, the Authority has allowed 25% of BOD expense be funded by ratepayers.

151. CL&P requested $467,000 DOL insurance.

152. Shareholders are the primary beneficiaries of DOL insurance.

153. In the past, the Authority has allowed 25% of DOL insurance expense be funded by ratepayers.

154. The Company originally requested an increase of $4.50 million for healthcare benefits expense but revised that amount to $4.21 million.

155. The total requested for healthcare benefits expense was $22.0 million.

156. The increase in the healthcare benefits expense is necessary to recover the normal escalation of healthcare costs.

157. The Company stated that the increase was determined in collaboration with Strategic Benefit Advisors, CIGNA healthcare and other trend survey data.

158. The Company used a self-funded program design.

159. CL&P's Test Year non-executive incentive compensation was $7.8 million.

160. The total non-executive incentive compensation requested for the Rate Year is $10.38 million.

161. The Company excluded executive incentive compensation expense of $8.7 million from the Application.

162. CL&P's variable pay program is designed to drive performance improvements and operational excellence.

163. The importance of incentivizing employees is to achieve higher standards of customer service and other goals.

164. Incentive compensation expenses should not be borne solely by the ratepayers.

165. The Authority has allowed some level of employee incentive compensation in previous decisions.

166. The Company included $4,765,000 of public liability expense for the Rate Year.

167. The Test Year liability expense was $1,955,000.

168. The initial proposed expense is an increase of $2,810,000 over the Test Year.

169. CL&P revised its public liability expense downward to $3,972,438 based on an updated actuarial report.

170. The total rent expense for the Test Year was $9.527 million.

171. The total proforma rent expense adjustment of $802,000 consisted of reductions of $680,000 to internal and $122,000 for external rent expenses.

172. The $680,000 reduction to the internal rent expense removes $623,000 associated with 56 Prospect Street in Hartford and $57,000 associated with the closure of facilities through consolidation.

173. CL&P included $203,269 for the NSTAR Corporate office in Boston, Massachusetts in the total external rent expense proposed for the Rate Year.

174. RRR manages NU's facilities and its internal rent expense that consists of interest, depreciation, property tax and equity return expenses.

175. The total internal rent expenses are allocated based on Test Year budgeted total payroll costs for NUSCO's employees.

176. CAU 99 allocation rates are used for directly and allocated RRR's rent expense.

177. CL&P allocated $4,047,520 out of the total rent expense of $8,578,534 for the Berlin Campus.

178. CL&P allocated $710,109 out of the total rent expense of $1,290,971 for the 3333 Berlin Turnpike Buildings.

179. CL&P allocated $1,651,607 out of the total rent expense of $3,818,745 for the Windsor CS facilities.

180. The first stage in the allocation internal rent expenses is based on the total square footages occupied by the NU operating companies and by NUSCO. The second stage involves the apportionment of the total operating companies' and NUSCO portions of the total rent amounts to the operating companies.

181. The allocation factors for CCC 048, 06F and 121 are used to allocate the total operating companies' portions of the total rent expenses for the RRR facilities to the operating companies.

182. The CCC 141 of 43.25% was used to allocate NUSCO's portion of total rent expense for the RRR facilities to CL&P distribution.

183. The ROE used to calculate the equity return costs included in the total rent expense for each of the RRR facilities is 9.92%.

184. The total rent expense for the Berlin Campus of $8,578,534 included total equity cost of $3,996,782.

185. The total rent expense for the 3333 Berlin Turnpike Buildings of $1,290,971 included total equity cost of $602,726.

186. The total rent expense for the Windsor CS of $3,818,745 included total equity costs of $1,800,458.

187. NSTAR shared service company merged into NUSCO effective January 1, 2014.

188. Approximately $59.874 million was billed to NSTAR Gas and Electric and $252.358 million was billed to CL&P by NUSCO.

189. Costs for facilities floor space should be allocated based on the projected square footage occupied.

190. In the 2009 CL&P Rate Case Decision, the Company was directed to be charged rent expense by NUSCO based on the square footage directly charged or allocated to CL&P.

191. The 9C allocator is based on NUSCO's employee labor costs and is used to allocate internal rent expense to CL&P.

192. The CCC 1NR allocator mirrors 9C, is based on NUSCO budgeted labor costs and does not allocate costs to the NSTAR companies.

193. For allocating NUSCO's costs to operating affiliates, the CCC 048 factors are based on square footage of the Berlin Campus using the C7 allocators.

194. Under the C7 allocation, the total CL&P distribution allocation factor is 32.94% and the NSTAR factor is 32.53%.

195. The facilities management costs for CCC 136 are allocated using the C7 Rate Code factors.

196. The C7 allocators are based on the new NUSCO's budgeted labor costs for both NU and NSTAR affiliates.

197. CL&P distribution has an allocation factor of 26.95% under the C7 formula.

198. The C7 allocator mirrors the 9C allocator, except that it is based on the new NUSCO's budgeted labor costs, not solely on the old NUSCO costs.

199. The 9C allocators are for the Test Year and rate C7 factors are for Rate Year.

200. The NUSCO Capital Funding expense funds certain capital investment that support shared services and the expense is shared among all NU subsidiaries using the shared capital investments.

201. The NUSCO Capital Funding expense for the Test Year was $2.701 million and $3.103 million was proposed for the Rate Year.

202. The NUSCO Capital Funding expenses are net of the capitalized portions of $0.805 million for the Test Year and $0.424 million for the Rate Year.

203. The total NUSCO Capital Funding expense, prior adjustment for the capitalized amount is $3.527 million for both the Test and Rate Years.

204. The $0.424 million represents 12.03% capitalization ratio for NUSCO's payroll costs in 2013.

205. The Company currently recovers in rates, $9.6 million annually to offset the cost of non-catastrophic storms when the Company's per-storm incremental expense is less than $5 million.

206. CL&P identified the Incremental Storm Expense of $9.6 million.

207. Incremental Storm Costs differ from the storm reserve in that they are included in base rates and the expense is funded throughout the year through customer rates.

208. Catastrophic storms are those events in which CL&P incurs incremental expense in excess of $5 million.

209. The storm reserve is currently funded through the distribution rate at the level of $3 million per year.

210. The Company proposed an amount for the annual storm reserve based on storm activity during the 2010-2013 period, excluding Storm Irene, the October 2011 Nor'easter and Storm Sandy.

211. The Company proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs for storms that meet specific criteria.

212. If the storm reserve accumulates a net balance of more than $50 million, then the Company will pay customers carrying charges at the weighted average cost of capital on the amount of the over-funding during the period of time that the over-funding situation exists. Conversely, the balance in the storm reserve falls below a net negative of $(50) million, then customers will pay carrying charges to the Company on the under-recovery during the period of time that under-recovery exists.

213. The Company has a means for recovery of catastrophic storm expense, which would be the request for the establishment of a regulatory asset to be recovered.

214. The Company sought recovery for storm costs that were not addressed in the Storm Cost Recovery Decision. These costs amount to $31.068 million and relate to the Windstorm of January 31, 2013, the blizzard of February 8, 2013, and remaining Hurricane Sandy costs that were not finalized at the time of the Storm Cost Recovery Decision.

215. The Company has not adjusted the 2013 storm costs to reflect the adjustments made in the Storm Cost Recovery Decision

216. CL&P proposed to utilize the storm reserve to fund $2 million per year for pre-staging costs.

217. The Company has used troubleshooters for decades.

218. The 2013 CAIDI was 107.1 minutes compared to a peer average of 102 minutes and CL&P's service scored at 604 compared to a peer average score of 655.

219. The cost of the new TSO is expected to be $10.7 million and that savings from the avoidance of cost for overtime work, associated rest periods, overtime meals and their meal time costs would save $5.7 million.

220. The total GET expense for the Test Year was $69.126 million.

221. The total GET expense proposed for the Rate Year is $85.203 million.

222. The total property tax expense for the Test Year was $66.231 million.

223. CL&P escalated known property tax mill rates to calculate the estimated property tax expense for the Rate Year.

224. The total estimated property tax expense for the 2014 list year was determined by escalating the 2013 list year's personal and real estate property mill rates by 4%.

225. The tangible personal property composite mill rate of 31.48 for the 2013 list year was escalated to 32.74 for the 2014 list year.

226. In the 2007 and 2009 CL&P Rate Case Decisions, the Authority directed CL&P not to escalate known mill rates.

227. For the 2014 list year, CL&P reported total plant additions of $233.789 million.

228. The total plant addition for calendar year 2014 is approximately $231.456 million.

229. The personal property declaration period for the 2014 list year runs from October 1, 2013 through September 30, 2014.

230. Nine months in 2014 falls within the 2014 list year declaration period.

231. Pursuant to Conn. Gen. Stat. §12-63(b)(6), the depreciated value of tangible personal property in the first year of declaration is 95% of acquisition costs.

232. The GRCF of 1.8252 was proposed for the Rate Year.

233. The GET rate of 7.072% was used calculate the proposed GRCF.

234. The total billed distribution revenue of approximately $977.414 million was used to calculate GET rate.

235. The total unbilled distribution revenue for the Test Year was approximately $1.622 million. The Company proposed rates that are based on a capital structure consisting of 50.38% common equity, 2.01% preferred stock and 47.61% long-term debt.

236. CL&P maintained its capital structure by coordinating in terms of timing and amount of common dividends paid to NU and the equity infusions that it receives from NU.

237. For the 12 months ended June 30, 2014, the Company's embedded cost of debt was 5.21%.

238. The long-term debt consists of 19 series of first mortgage bonds and nine series of pollution control revenue notes.

239. CL&P's proposed long-term embedded cost of debt is 5.45%, based on the 2013 Test Year equity ratio of 50.38%.

240. The Company proposed $116,919 in preferred stock in its capital structure as of December 31, 2015, at a cost of 4.80%.

241. CL&P has 13 series of perpetual preferred stock that was issued between 1947 and 1968. The determination of the cost of equity in this proceeding was

obtained using the DCF model and CAPM method to a proxy group of companies.

242. The Company's cost of equity testimony was prepared by Robert Hevert, a financial consultant on behalf of CL&P.

243. The Company advocated an allowed ROE of 10.20% from a range of 10.20% to 10.70%.

244. Mr. Hevert relied on a DCF model (including the Constant Growth, Quarterly Growth, and Multi-stage forms), the CAPM (including both the traditional form of the CAPM and the Empirical CAPM), and the Bond Yield Plus Risk Premium approach to develop his cost of equity results by applying to a proxy group of electric utilities.

245. Mr. Hevert did not make an explicit adjustment to his recommended ROE of 10.20% for flotation costs, but computed a 14-basis point adjustment to reasonably represent flotation costs for the Company.

246. Mr. Hevert's cost of equity calculations were primarily based on a proxy group of only 14 publicly traded utility companies.

247. To determine the composition of the proxy group, Mr. Hevert began with the universe of 47 companies from Value Line's Electric Utilities Industry.

248. Mr. Hevert applied the following screening criteria to determine his recommended proxy group: 1) consistently pay quarterly cash dividends; 2) covered by at least two utility industry equity analysts; 3) investment grade senior unsecured bond and/or corporate credit ratings from S&P; 4) regulated operating income over the three most recently reported fiscal years comprised of at least 60% of the respective totals for that company; 5) regulated electric operating income over the three most recently reported fiscal years represent at least 90% of total regulated operating income; and 6) not known to be party to a merger, or other significant transaction as of July 31, 2014.

249. Mr. Hevert calculated the dividend yield based on the proxy companies' current annualized dividends and average closing stock prices over the 30, 90 and 180 trading day periods ended July 31, 2014.

250. Mr. Hevert used a consensus of long-term earnings growth estimates from Zacks, First Call and Value Line.

251. Mr. Hevert included the sustainable growth approach to estimating a company's expected growth.

252. The Company's constant growth DCF results, including sustainable growth, produced a range of 7.58% to 10.95%.

253. Mr. Hevert used two measures of a 30-year Treasury bond yield and estimated a current rate of 3.35% and a near-term projected rate of 4.03% as the risk-free rates in the CAPM.

254. Mr. Hevert calculated three versions of the market risk premium. He relied on two forward-looking estimates and included a third estimate that is a simple average of the ex-ante method, Supply Side model, and the long-term historical average market risk premium.

255. Mr. Hevert produced CAPM results in the range of 9.46% to 11.96%, a decrease from the prior range of 9.74% to 12.16%.

256. Mr. Hevert included the ECAPM analysis in estimating the cost of equity, which is another variation of the CAPM.

257. Besides the traditional CAPM and ECAPM, Mr. Hevert evaluated the cost of equity utilizing the bond yield plus risk premium method.

258. The OCC's cost of capital witness, Dr. Woolridge, advocated a 8.90% ROE in this proceeding based on the capital structure proposed by CL&P which includes a common equity ratio of 50.38%.

259. Using the proposed Test Year capital structure and senior capital cost rates, OCC recommended an overall rate of return of 7.14%.

260. Dr. Woolridge employed the use of the DCF and CAPM approaches to a 32-member electric proxy group, as well as, Mr. Hevert's proxy group of companies.

261. The average S&P bond ratings for the Woolridge and Hevert proxy groups are both BBB+, while CL&P's bonds are rated A-.

262. In developing a fair rate of return for CL&P, Dr. Woolridge primarily relied on the DCF model to estimate the cost of equity and applied it to the both Mr. Hevert's proxy group and his 32-member proxy group.

263. Using the constant growth version of the DCF method, Dr. Woolridge first calculated the dividend yield by taking the current annual dividend and the 30-day, 90-day and 180-day average stock prices as of July 17, 2014. To reflect the growth over the coming period, Dr. Woolridge adjusted the dividend yields by one-half the expected dividend growth resulting in an adjusted dividend yield of 3.9% for Woolridge's proxy group and 4.0% for Hevert's proxy group.

264. For the growth component of the DCF calculation, Dr. Woolridge employed 13 measures of growth, of which 6 measure historic growth, and 7 are *Value Line* or Wall Street analysts' projections of growth, giving primary weight to the projected EPS growth rate forecasts of analysts.

265. To derive the overall growth rate for the proxy groups, Dr. Woolridge used the midpoint of the median range for each resulting in a DCF growth rate of 4.875%

for Woolridge's proxy group and 5.0% for Hevert's proxy group, giving greater weight to the projected growth rate figures.

266. Dr. Woolridge calculated equity costs rates of 8.80% and 9.0%, for Woolridge and Hevert's proxy group, respectively.

267. Dr. Woolridge performed a CAPM analysis using both proxy groups.

268. Dr. Woolridge elected to use 4.0% as the risk-free rate in the CAPM analysis.

269. The median betas for the companies in Woolridge's and Hevert proxy groups are 0.75% for both.

270. To determine an equity risk premium, the OCC reviewed the results of over 40 equity risk premium studies and surveys performed over the past decade.

271. Dr. Woolridge claimed that much of the data indicates that the market risk premium is in the 4.0% to 6.0% range and the midpoint of 5% is used as the market risk premium for OCC's CAPM analysis.

272. Dr. Woolridge's CAPM resulted in a cost of equity of 7.80% for both proxy groups.

273. The OCC concluded that the appropriate equity cost rate for the proxy groups is in the 7.80% to 9.00% range.

274. Dr. Woolridge did not take into consideration the impact of the Company's proposed decoupling mechanism nor the earnings sharing mechanism on the OCC recommended ROE. He concurred that the mechanisms are reflected in the lower risk of the company.

275. Dr. Woolridge provided the authorized ROEs in 18 rate cases in 2013 and 2014 involving distribution-only electric utilities. There are no authorized ROEs of 10% or higher, and the average for the distribution-only electrics is 9.48%.

276. There is a declining trend in authorized ROEs, particularly for distribution-only utilities. According to data from Regulatory Research Associates, the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%.

277. The average reported ROE for distribution-only utilities was 9.57%, which is 63 basis points lower than CL&P's proposed ROE.

278. In 16 recent utility rate cases in which Mr. Hevert provided expert testimony, the approved ROE decided in each case was lower than Mr. Hevert's recommended ROE in all 16 cases.

279. The AG generally supported the OCC's cost of capital testimony and its recommended ROE of 8.9%.

280. To calculate a flotation adjustment, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs.

281. The Company did not identify any test-year flotation costs.

282. CL&P has incurred the issuance expenses associated with NU's dividend reinvestment plan, which is only at the parent company level.

283. The record also indicates that NU has not executed any common stock offerings since the filing of CL&P 2009 Rate Case.

284. Interest rates and long-term utility bond yields remain at historical low levels and are below the levels existing at the time of the 200r CL&P Rate Case.

285. The economic outlook now for several years has promised economic recovery and the rise of interest rates which have not occurred.

286. The average ROEs for the electric and gas industries continue to trend downward.

287. At the time CL&P's last ROE was set at 9.40%, the annual average allowed ROE for the electric industry was 10.48% for 2009.

288. In 2013 to 2014, there have been no authorized ROEs of 10% or higher and the average for the distribution-only electrics is 9.48%.

289. The Company and OCC did not suggest an adjustment to their recommended ROEs to quantify an impact for decoupling.

290. Revenue stabilization and cost recovery mechanisms, such as decoupling, are already reflected in current market valuations of the proxy companies.

291. Both S&P and Fitch upgraded CL&P's ratings due to the merger between NU and NSTAR.

292. 2009 CL&P Rate Case, the Company has increased its S&P bond rating from BBB to the present A-, two notches.

293. As of June 24, 2014, the Company has credit ratings of A- (outlook: Positive), Baa1 (outlook: Stable), and BBB+ (outlook: Stable) from S&P, Moody's and Fitch, respectively.

294. Since 2009, the Company has a stronger times interest earned ratio, fixed coverage ratio, profit margin, return on total assets and return on total capital.

295. The investment risk of public utilities is still relatively low compared to the market as a whole (1.0 beta) as evidenced by the drop in NU's beta from .80 in 2009 to .75 currently.

296. CL&P continues to maintain a strong financial position, limited risk profile, visible forward earnings stream, a stable dividend yield, strong balance sheet and strong cash position.

297. Despite the decline in interest rates, utilities continue to outperform most sectors of the bond market.

298. The cost of equity for the electric industry is among the lowest of all industries in the U.S.

299. The Authority has established the sharing threshold at the Company's allowed ROE with the sharing distributed equally with 50% to shareholders and 50% for the customers.

300. Since 1999, the Company has operated under an ESM whereby earnings in excess of the allowed ROE are shared with ratepayers.

301. Conn. Gen. Stat. §16-19(g) allows the Authority to review a company's earnings if an earned ROE exceeds a company's authorized ROE by 1% point for a period of six consecutive months, equivalently two fiscal quarters.

302. The Authority has a long tradition of using an ESM and has approved these for companies as an incentive to shareholders.

303. Implementation of an ESM allows shareholders to capture a portion of potential overearnings and avoid an overearnings financial review that would be otherwise initiated by the Authority.

304. ESMs have been implemented in the past for electric, gas and water utilities.

305. The current ESM is also consistent with other recent ESMs that were approved by the Authority.

306. In its 2011 Storm Decision, the Authority stated that it was establishing a rebuttable presumption that CL&P should have imposed on it an appropriate reduction to its allowed return on equity in its next ratemaking proceeding as a penalty for poor management performance and to provide incentives for improvement.

307. In the Merger Decision, the Authority approved the merger agreement between Northeast Utilities and NSTAR.

308. A condition of the merger settlement agreement provided that any future recovery of transaction costs are subject to Authority review and approval in a future rate proceeding.

309. This docket is the first rate case since the merger was approved.

310. The Authority found in the Merger Docket that total net benefits of approximately $783.8 million were expected on an overall, enterprise-wide basis with an estimated $301.8 million allocable to CL&P's transmission and distribution operations.

311. The Company submitted an updated merger integration report integration forecasting an increase, in merger savings on an enterprise-wide basis of $92.8 million for a total of $876.6 million.

312. The decoupling statute requires the adjustment or reconciliation be made on the basis of "actual distribution revenues."

313. No other utility in Connecticut has sought and the Authority has not approved any such exception for revenues to be retained in excess of those allowed to meet revenue requirements.

314. Decoupling is not a rate developed to recover underlying, prudently incurred costs; it is a true-up mechanism for revenues previously designed fully in accordance with the Authority's just and reasonableness responsibility.

315. The potential loss of revenue from new service customers is more than balanced from the protection ratepayers stand ready to provide should sales decrease for any reason.

316. Decoupling is only a true-up mechanism that involves minimal dollars in comparison to total distribution revenues.

317. Decoupling is not an appropriate alternative to increasing fixed charges.

318. CL&P traditionally used statistically adjusted end-use models to forecast sales by customer class.

319. The Company performed a weather normalization study in developing the rate year sales forecast and associated revenues.

320. In 2011, CL&P lost approximately 159 GWh, or 2.2% of its sales for the affected period, due to Hurricane Irene and the October 2011 snowstorm.

321. In 2012, CL&P lost approximately 86 GWh, or 2.6% of its sales for the affected period, due to Hurricane Sandy.

322. The Company recently increased its C&LM spending, and will lose additional sales which are not reflected in historical sale trends, that only include the base conservation savings.

323. Rate Year revenues for reconnect fees for 2013 are low compared to prior years.

324. The Rent from Electric Property, could not be calculated as the billing determinants for pole attachments is not available.

325. CL&P has an agreement with Verizon from 1956 that gives all recurring attachment revenues for the communications gain on jointly owned poles to Verizon, and pre-dates the existence of cable television and fiber pole attachments.

326. CL&P did not recover all of its pole attachment make-ready expense in the Test Year.

327. CL&P does not have explicit authority to collect all make-ready expenses from pole attachers.

328. A COSS is a mathematical business model that systematically assigns cost responsibility among customer classes for company assets and expenses incurred by an EDC to serve customers.

329. A COSS is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class.

330. The Company followed the detailed methodology consistently approved by the Authority in past rate case Decisions.

331. The Company relied on its COSS results when designing rates.

332. FERC established a new operating standard designed to save energy losses in transformers.

333. The NARUC Manual requires plant installed to service customers and meet their peak demand, must be segmented into customer and demand related costs.

334. The NARUC Manual states that the customer component of distribution facilities is that portion of costs which varies with the number of customers.

335. The NARUC Manual recommends that either the minimum intercept method or other methods like the minimum distribution system method be undertaken to discern customer and demand cost components.

336. The Authority held in Docket No. 90-12-03 that the simplicity of the minimum-size methodology warrants its continued use by CL&P in future COSS.

337. A genuine, but minimal, distribution system is necessary for a utility to stand ready at no load or to serve nominal loads.

338. In Docket No. 05-06-04, the Authority rejected the OCC’s recommendations that no costs be allocated based on the number of customers.

339. In Docket No. 08-07-04, the Authority rejected the OCC’s request for allocation on the basis of demand only.

340. Poles and lines are installed to expand circuits to reach new off-circuit customers.

341. Some minimum size cable is necessary to simply reach all customers.

342. kVA levels differ dramatically between residential neighborhoods and industrial parks.

343. Transformers are needed to expand circuits to reach customers and are sized to reflect differing kVA demands.

344. Newer transformer designs will operate with less energy lost as heat.

345. The COSS methodology submitted by the Company can be relied upon for designing rates.

346. To reduce interclass subsidies, all classes should be moved closer to their cost to serve, or closer to the system average ROR, while applying the principles of rate gradualism.

347. The farther the class is from the system average, the larger the percentage increase/decrease necessary to align the class revenues to the average.

348. To reduce inequities between classes, it is necessary to align the rate classes as close to the system ROR as possible.

349. The Company's rate design moved rates in each rate class closer to their actual cost of service, both at a total class level and with respect to the prices for distribution service within each rate class.

350. The Company's rate design moved the ROR for each rate class closer to the average ROR by allocating a greater/lesser than average percentage distribution increase, depending on their current ROR.

351. CL&P's rate design decreased or eliminated per kWh charges, and moved customer and demand charge rates closer to their cost-of-service levels.

352. CL&P's rate design proposal was designed to collect a total distribution revenue increase of $231.6 million.

353. For Rate 1, CL&P set a distribution rate revenue target of $570.4 million, an increase of $148.2 million or 35.11% over its current distribution revenue of $422.5 million.

354. CL&P's rate design for Rate 1 included a 59% increase to the Customer Charge and a 2.64% increase to the per-kWh Charge.

355. If the COSS classified distribution facilities on a full demand basis, without classifying the plant costs as customer-related, the study would support a customer charge no higher than $11.68.

356. The low-use customers in Rate 1 will face the largest percentage bill increases from the proposed customer charge increase.

357. The OCC, BETP, ENE and AG objected to the 59% increase in the customer charge.

358. The Authority received an unprecedented number of comments from customers, public officials and consumer advocates on the proposed rate increase, especially the 50% increase in the Rate 1 Customer Charge.

359. Decoupling removes any Company sales-related disincentive to promote energy efficiency and distributed generation, and assures cost-recovery for the Company.

360. A potential 10% savings in distribution charges has not induced a large customer migration to TOD pricing.

361. CL&Ps rate design for Rates 27, 30 and 40 include increases to the Customer Charge in excess of 40%.

362. New rates will not be implemented until after final approval of the Rate Plan.

363. The customer bill impact of the distribution rate increase will be mitigated by a subsequent decrease of the storm related costs which will be removed from the NBFMCC effective January 1, 2015.

364. Recurring charges for pole attachments are typically fees for rental of pole space, and non-recurring fees typically include items such as make-ready costs.

365. Municipal Rate customers are allowed an exemption from pole attachment fees for their first attachment on any pole.

366. The pole attachment rates are billed on a semi-annual basis.

367. The Pole Attachment Order methodology uses historic (embedded) costs while CL&P uses a combination of historic and reproduction (marginal) costs, which the FCC has expressly rejected.

368. The Pole Attachment Order methodology applies cost allocators of 66% in urban areas and 44% in rural areas while CL&P applies higher cost allocators of 69.18% in urban areas and 45.38% in rural areas.

369. The Pole Attachment Order methodology allocated pole costs using a presumption of 13.5’ of usable space on the pole to derive a space allocation factor while CL&P uses 12.33’ without providing a pole survey.

370. NECTA conducted a Pole Survey and calculated a usable space factor for pole attachments of 14.57'.

371. In Docket No. 09-12-05, the Authority approved the unbundling of street lighting rates into their functional components.

372. The Company's unbundled rate design of Rate 116 set pricing for the system component of rates and the equipment and O&M components of rates.

373. The Company designed a two-part charge for Rate 117 consisting of customer and demand components that applies to applicable fixtures connected to the CL&P's distribution system.

374. The revenue targets for customer and demand were derived by applying a 75% / 25% proportion of demand and customer costs, respectively.

375. For Rate 116, additional equipment and O&M charges apply.

376. The same methodologies for determining the system, equipment and O&M rates for other Rate 117 offerings have been applied in developing proposed new LED street lighting distribution rates.

377. The proposed rates in the T&C for Delivery Service were developed based on the cost of providing service.

378. In the past, the Authority approved CL&P's request to discontinue the surge protection program.

379. CL&P offers a TOD rate option, Rate 7, for residential non-heating customers, of which Rate 5 customers may elect to receive service.

380. Rate 7 was designed based on the service characteristics of the non-heating residential class Rate 1, and on methodologies and guidelines developed and approved by the Authority.

381. Less than 500 customers receive service on Rate 7 compared to over 1.1 million customers on Rate 1 and Rate 5.

382. Rate 5 is a legacy tariff and new customers are no longer allowed to take service under that rate.

383. The Reconnection at the Meter Charge has not changed in many years, despite increases to general rates.

384. CL&P's standard bill form, termination notice and customer rights notice comply with applicable regulations.

385. For calendar year 2014, less than 1.5% of bills issued were estimated.

386. CL&P's estimated bill form complies with applicable regulations.

387. CL&P's policies and procedures for the administration of customer security deposits comply with applicable regulations.

388. In November 2012, CL&P discontinued the practice of on-site energy audit service appointments at a customer's location.

389. NUStart became a one-year program in calendar year 2013.

390. CL&P's Call Center performance statistics were acceptable as filed.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented in this proceeding, the Authority finds allowed revenues of $1.033 billion to be appropriate for CL&P in the Rate Year as detailed in Appendix A. This is a reduction of $93 million from the Company's adjusted cumulative request of $1.127 billion and a $134.076 million increase or 13.9% to present revenues. The Authority allows the Company an allowed rate base of $3.233 billion. The Authority approves an allowed ROE of 9.02% for 2015, inclusive of a one year penalty of 15 basis points for 2011 Storms response. The allowed capital structure consists of 50.38% common equity, 2.01% preferred stock, and 47.61% long-term debt components. The revenue requirement adjustments as authorized herein will be sufficient to enable the Company to operate successfully, maintain its financial integrity, attract capital, compensate its investors for the use of their money and the risks assumed, and maintain high quality service. New rates will become effective for usage on and after December 1, 2014. The Authority will reopen this proceeding for the purpose of further reviewing and ruling on issues identified herein related to the repair tax deductions and accumulated deferred income taxes.

B. ORDERS

For the following Orders, submit one original of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, Connecticut 06051 and file an electronic version through the PURA's website at www.ct.gov/pura. Submissions filed in compliance with the PURA's Orders must be identified by all three of the following: Docket Number, Title and Order Number.

1. Beginning on December 17, 2014, the Company, for each restoration event that it incurs in excess of $20 million, shall submit to the Authority its proposed cost recovery utilizing its standard accounting practices as well as a proposed recovery using the accounting treatment that was utilized in the Decision in Docket No. 13-03-23. This filing shall be made with the Authority within 30 days of full restoration of the event.

2. No later than December 31, 2014, the Company shall submit a final Rate Plan for Authority approval that incorporates the directives herein as outlined in Section II.J.5. Rate Design, Section II.J.8. Tariff Changes, and also include the following:

   a. the CATV Rate and Telecom Rate as discussed in Section II.J.6. Pole Attachment Rates and the Company shall prorate the December charge in accordance with its proposal; and
   b. a new Decoupling Tariff Rider as discussed in Section II.H. Decoupling.

3. No later than January 30, 2015, CL&P shall file a copy of its 2013 income tax return with the IRS with the Authority. The filing shall include all applicable schedules and forms supporting tax elections made or requested. Additionally, the filing shall include a worksheet showing portions of the tax depreciation deductions reported on Form 4562 that are applicable to distribution plant-in-service.

4. No later than January 30, 2015, CL&P shall acknowledge in writing that it will submit for the Authority's approval, any changes to its customer service practices, procedures or policies in writing at least 20 business days prior to the effective date of such changes.

5. No later than February 16, 2015, the Company shall file a final-rates COSS reflecting rate year billing determinants, the financial profile approved in this Decision and the then current rates developed in accordance with the Rate Plan approved herein.

6. No later than March 31, 2015 and each year thereafter until its next rate case, the Company shall report the CAIDI for the second and third shifts and for weekends and the average number of contract workers staffing each work period to demonstrate the change that the new TSO had on reliability for these periods and the overall system and report the annual contractor costs of the new TSO.

7. No later than March 31, 2015, 2016 and 2017, the Company shall provide the Authority with a report of actual construction program capital spending by Initiative or category for the preceding year. If actual spending varies from budgeted spending by more than 10% in any initiative or category from that budgeted, or if the total aggregate capital spending varies by more than 10%, the Company shall provide an explanation of the reason for such variance.

8. No later than April 1, 2015, the Company shall report on the status of introducing a phase-out formula concerning revenue true-ups in their next scheduled CAM and FMCC reconciliation filings.

9. No later than April 1, 2015, CL&P shall provide a proposal that addresses the OCC's concerns regarding its joint pole agreement with Verizon.

10. No later than September 30, 2015, CL&P shall file a copy of its 2014 Federal income tax return with the Authority. The filing shall include all applicable schedules and Form 3115 filed requesting accounting changes regarding the RTD election pursuant Revenue Procedure 2012-20. Additionally, the filing shall

include a worksheet showing portions of the tax depreciation deductions reported on Form 4562 that are applicable to distribution plant-in-service and a summary of the RTD amounts for the appropriate calendar years.

11. No later than November 30, 2015 and 2016, the Company shall provide the Authority with the budget of construction program capital spending by initiative or category for the following year.

12. No later than February 15, 2016 and annually thereafter, the Company shall file its proposed decoupling rate for the upcoming 12-month period.

13. Beginning January 31, 2016, and annually thereafter for the term of this rate plan, the Company shall report to the Authority unused amounts of pre-staging costs that are transferred to the storm reserve.

14. In its first Decoupling Mechanism reconciliation filing, the Company shall adjust its allowed revenue requirement target to reflect the ROE penalty imposed in Section II.F.4 ROE Penalty.

15. In its next rate case, the Company shall submit a:

    a. Depreciation Study.
    b. Complete and well documented analysis of expected service periods for its existing and new software systems and provide such analysis to the Authority prior to its next rate proceeding.
    c. Report on the annual CAIDI and JD Power service scores for CL&P since 2013 and its peer group and justify the effect that the new TSO had on these results. COSS that is methodologically consistent with the study performed in the instant application.
    e. Second COSS that utilizes a zero-intercept methodology for segmenting plant included in the current minimum-size-of-facilities method into customer and demand categories.
    f. Rate design that utilizes a rate year COSS that reflects the methodology approved in the instant case.

V. RATE MODEL

A. 2015

1. Income Statement

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
INCOME STATEMENT — 12/16/2014 — PER CENT REVENUE INCREASE ALLOWED = **14.3058%**
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2014
FROM APPLICATION FILED 09/22/2014

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$905,882	$616	$906,498		$906,498
OPERATING REVENUES - OTHER		0	0		0
RATE REQUEST	221,098	0	221,098	(91,416)	129,682
TOTAL REVENUES	1,126,981	616	1,127,597	(91,416)	1,036,180
OPERATION & MAINTENANCE EXPENSE	$375,418	(21,366)	$354,052	(277)	353,775
OTHER O&M		0	0		0
MISC. EXPENSE		0	0		0
DEPRECIATION EXPENSE	150,372	(7,440)	142,932		142,932
AMORTIZATION EXPENSE	61,662	34	61,696		61,696
MISC. EXPENSE		0	0		0
TAXES, SALES & PAYROLL	11,449	(414)	11,035		11,035
GROSS EARNINGS TAXES	85,203	(96)	85,107	(6,455)	78,653
PROPERTY TAXES	81,435	(1,988)	79,447		79,447
PROVISION FOR DEF. INCOME TAXES, NET	27,885	3,039	30,924	0	30,924
STATE TAXES	6,744	2,603	9,347	(7,622)	1,725
FEDERAL TAXES (CURRENT)	60,700	9,212	69,912	(26,972)	42,940
INVESTMENT TAX CREDIT	(954)	0	(954)		(954)
TOTAL OPERATING EXPENSES	$859,914	(16,415)	$843,499	(41,325)	$802,173
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$267,067	$17,031	$284,098	(50,091)	234,008

2. Rate Base

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
RATE BASE LAST REVIEW DATE 12/16/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2014

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	5,257,802	(4,510)	$5,253,292
PLANT 2			0
LESS: CONS. WORK IN PROGRESS		0	0
LESS: ACCUM DEP AND AMORT	1,312,534	(3,720)	1,308,814
NET PLANT	3,945,268	(790)	3,944,478
PLUS:			
MATERIALS & SUPPLIES	$54,818	0	54,818
WORKING CAPITAL	17,230	(1,869)	15,361
PREPAYMENTS	4,655	0	4,655
DEFERRED TAXES - CIAC	38,418	0	38,418
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
REGULATORY ASSET - FASB 158		0	0
DEFERRED ASSETS, NET OF TAXES	191,788	(17)	191,771
LESS:			
ACCUM. DEFERRED INCOME TAXES	$789,750	171,583	961,333
CUST. ADVANCES AND DEPOSITS	15,406	0	15,406
STORM RESERVES		0	0
DEFERRED INCOME TAXES - FAS 158		0	0
ALLOWANCE FOR BAD DEBT		0	0
PENSION LIABILITIES		0	0
RESERVES, NET OF TAXES	40,555	(1,775)	38,780
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
RATE BASE	3,406,466	(172,484)	3,233,982
RETURN ON RATE BASE	7.83%	7.24%	7.24%
OPERATING INCOME	266,739	(32,731)	234,008

B. 2016

1. Income Statement

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
INCOME STATEMENT — 12/15/2014 — PER CENT REVENUE INCREASE ALLOWED = **14.7905%**
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2015
FROM APPLICATION FILED 09/22/2014

	REVISED PRO FORMA RATE YEAR	AUTHORITY ADJUSTMENTS	TABLE II	FINAL CHANGES	TABLE III
OPERATING REVENUES	$905,882	$616	$906,498		$906,498
OPERATING REVENUES - OTHER		0	0		0
RATE REQUEST	221,098	0	221,098	(87,022)	134,076
TOTAL REVENUES	1,126,981	616	1,127,597	(87,022)	1,040,574
OPERATION & MAINTENANCE EXPENSE	$375,418	(21,366)	$354,052	(264)	353,788
OTHER O&M		0	0		0
MISC. EXPENSE		0	0		0
DEPRECIATION EXPENSE	150,372	(7,440)	142,932		142,932
AMORTIZATION EXPENSE	61,662	34	61,696		61,696
MISC. EXPENSE		0	0		0
TAXES, SALES & PAYROLL	11,449	(414)	11,035		11,035
GROSS EARNINGS TAXES	85,203	(96)	85,107	(6,144)	78,963
PROPERTY TAXES	81,435	(1,988)	79,447		79,447
PROVISION FOR DEF. INCOME TAXES, NET	27,885	3,039	30,924	0	30,924
STATE TAXES	6,744	2,604	9,348	(7,255)	2,093
FEDERAL TAXES (CURRENT)	60,700	9,216	69,916	(25,676)	44,241
INVESTMENT TAX CREDIT	(954)	0	(954)		(954)
TOTAL OPERATING EXPENSES	$859,914	(16,409)	$843,505	(39,339)	$804,166
INCOME FROM LEASE OF UTILITY PLANT	0	0	0		0
OPERATING INCOME	$267,067	$17,025	$284,092	(47,683)	236,409

2. Rate Base

THE CONNECTICUT LIGHT AND POWER COMPANY - DN 14-05-06
RATE BASE LAST REVIEW DATE 12/15/2014
ELECTRIC - RATE YEAR STARTING DECEMBER 1, 2015

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	5,257,802	(4,510)	$5,253,292
PLANT 2			0
LESS: CONS. WORK IN PROGRESS		0	0
LESS: ACCUM DEP AND AMORT	1,312,534	(3,720)	1,308,814
NET PLANT	3,945,268	(790)	3,944,478
PLUS:			
MATERIALS & SUPPLIES	$54,818	0	54,818
WORKING CAPITAL	17,230	(2,451)	14,779
PREPAYMENTS	4,655	0	4,655
DEFERRED TAXES - CIAC	38,418	0	38,418
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
REGULATORY ASSET - FASB 158		0	0
DEFERRED ASSETS, NET OF TAXES	191,788	(17)	191,771
LESS:			
ACCUM. DEFERRED INCOME TAXES	$789,750	171,583	961,333
CUST. ADVANCES AND DEPOSITS	15,406	0	15,406
STORM RESERVES		0	0
DEFERRED INCOME TAXES - FAS 158		0	0
ALLOWANCE FOR BAD DEBT		0	0
PENSION LIABILITIES		0	0
RESERVES, NET OF TAXES	40,555	(1,775)	38,780
ACCUM. DEFERRED INCOME TAXES - FAS 10	391,860	0	391,860
RATE BASE	3,406,466	(173,066)	3,233,400
RETURN ON RATE BASE	7.83%	7.31%	7.31%
OPERATING INCOME	266,739	(30,329)	236,409

DOCKET NO. 14-05-06 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

This Decision is adopted by the following Commissioners:

Arthur H. House

Michael A. Caron

This Decision is adopted, in part, and dissented to, in part, by the following Commissioner:

John W. Betkoski, III

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Nicholas E. Neeley
Acting Executive Secretary
Public Utilities Regulatory Authority

12/17/14
Date

DOCKET 14-05-06
APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY FOR A RATE INCREASE

DISSENTING OPINION, IN PART, OF VICE CHAIRMAN JOHN W. BETKOSKI, III

Every Commissioner at the Connecticut Public Utilities Regulatory Authority (PURA or Authority) has the right to a dissenting opinion. I'm exercising this right at this time. My dissenting opinion in the instant proceeding was not an easy decision. However, my experience in utility rate making is the basis for my decision. My dissenting opinion is on the allowed return on equity (ROE) authorized by this Authority.

The determination of the cost of capital was a large part of this CL&P rate case proceeding. The cost of capital includes both the cost of equity and the cost of debt. The basis for the determination of an overall cost of capital is articulated in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), in which the Court established criteria to determine cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk. By Connecticut law, utilities are entitled to a level of revenues that will allow them ". . . to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable." Connecticut General Statutes (Conn. Gen. Stat.) §16-19e(a)(item 4).

To determine a rate of return (ROR) on rate base that is appropriate for a utility's overall cost of capital, the Authority first identifies the components of a utility's capital structure. A capital structure is defined as the permanent long-term financing of a company which consists of long-term debt, preferred stock, and equity. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the utility's overall cost of capital, which becomes the allowed rate of return on rate base. The most difficult and controversial cost of capital component to determine is the ROE. My dissension centers on the determination of this ROE.

In order to determine an allowed ROE the risks that investors face must be considered as well as what a rational investor's expectations are. An investment of any kind results in an opportunity cost to the investor. This opportunity cost is best thought of as the cost of using capital for a certain investment as measured by the benefit of revenues given up (opportunity loss) by not using the capital in the next best alternative investment. An equity investor forgoes the use of their money in exchange for a set of expectations being a series of cash dividend payments, recovery of their initial investment, and also some growth in their initial investment. The key wordin this is expectations because the concept of risk relates to expected not realized returns on an investment.

I find that the Authority has properly calculated the discounted cash flow (DCF), capital asset pricing model (CAPM), and risk premium methodologies in coming to a conclusion of a 9.17% ROE. Market data was used as close to the date of this decision as possible to make for a timely allowed market based ROE. The simple fact is I believe this Authority should consider the use of data of average ROE's as published by Regulatory Research Associates (RRA). This is a well-respected publication used by state commissions as well as utilities. ROE data from other state commissions should also be used. From my seventeen years as a commissioner at this Authority, I have found that RRA has been consistently used as a benchmark for ROE determination. The ROE awarded by a commission should be commensurate with other utilities in the same industry. If a utility consistently has a lower ROE than peer utilities, this will put that utility at a disadvantage in attracting investor capital.

CL&P is currently at an allowed ROE of 9.40% and requested an allowed ROE of 10.20% in this proceeding. The record indicates that RRA, calculated the average of 101 reported electric utility rate case ROEs authorized by commissions in 2012, 2013 and so far in 2014, is 9.91%, with a reported range of 8.72% to 10.95%. Chriss PFT, p, 18. These electric utilities are both distribution and integrated.

The record also indicates that distribution only electric utilities allowed ROEs for 2013 and 2014 are the following:

Date	State	Utility	Docket/Case Number	Authorized ROE
1/16/2013	Texas	Cross Texas	Docket No. 40604	9.60%
1/16/2013	Texas	Wind Energy Transmission Texas	Docket No. 40606	9.60%
2/22/2013	Maryland	Baltimore Gas and Electric Co.	Case No. 9299	9.75%
3/14/2013	New York	Niagara Mohawk Power Corp.	Docket No. 12-E-0201	9.30%
5/1/2013	Ohio	Duke Energy Ohio Inc.	Case No. 12-1682-EL-AIR	9.84%
6/21/2013	New Jersey	Atlantic City Electric Co.	Docket No. ER-12121071	9.75%
7/12/2013	Maryland	Potomac Electric Power Co.	Case No. 9311	9.36%
8/14/2013	Connecticut	United Illuminating Co.	Docket No. 13-01-19	9.15%
10/3/2013	Texas	Southwestern Electric Power Co	Docket No. 40443	9.65%
12/9/2013	Illinois	Ameren Illinois	Docket No. 13-0301	8.72%
12/13/2013	Maryland	Baltimore Gas and Electric Co.	Case No. 9326	9.75%
12/18/2013	Illinois	Commonwealth Edison Co.	Docket No. 13-0318	8.72%
2/20/2014	New York	Consolidated Edison Co. of NY	Case No. 13-E-0030	9.20%
3/17/2014	New Hampshire	Liberty Utilities Granite St	Docket No. DE-13-063	9.55%

3/26/2014	District of Columbia	Potomac Electric Power Co.	Formal Case No. 1103-2013-EL	9.40%
4/2/2014	Delaware	Delmarva Power & Light Co.	Docket No. 13-115	9.70%
5/16/2014	Texas	Entergy Texas Inc.	Docket No. 41791	9.80%
5/30/2014	Massachusetts	Fitchburg Gas & Electric Light	DPU 13-90	9.70%
7/2/2014	Maryland	Potomac Electric Power Co.	Case No. 9336	9.62%
			Average	9.48%

Woolridge PFT, Exhibit JRW-12, p. 3.

Using the allowed ROE data from RRA and other sources is much like the comparable earnings (CE) methodology in determining an allowed ROE. The CE methodology in its simplest form compares other utilities with the same risk characteristics with the utility in question and averaging the returns found to be applicable. I believe the risk characteristics of the electric companies found in RRA are comparable to Connecticut Light and Power Company (CL&P). More importantly' I believe investors consider the whole electric utility industry and look to the opportunity of electric companies to earn a fair rate of return as embodied in the allowed ROE authorized by their various state utility commissions. With this said, my experience tells me that critics will say that the drawback of using this methodology is stale data from allowed returns that were set some time ago so as to preclude current market data. I counter this argument with the fact that these allowed ROEs, whenever set, are currently in effect and that the electric utility has the opportunity to earn revenues based on those allowed ROEs. Investors have a choice as to where to put their investment capital and in my opinion one of the paramount factors in investor decision making is how high the allowed return is for a specific electric utility. Other ROE proxies that can be used, for a determination of an allowed ROE for CL&P, are an allowed ROE for Western Massachusetts Electric Company (WMECO) currently at 9.60% and Public Service of New Hampshire (PSNH) at an allowed ROE of 9.67% which are both electric utility operating companies of CL&P's parent company Northeast Utilities (NU).

The determination of an allowed ROE is a balance between revenue requirements paid by ratepayers and the financial integrity of CL&P. The higher the allowed ROE the greater the revenue requirement paid by ratepayers. However, the higher the ROE, the greater is the financial integrity of CL&P. This is shown in the credit rating of CL&P which is currently at an A- credit rating. This credit rating is a primary factor in the cost of borrowing which is an expense passed on to ratepayers. An allowed ROE needs to strike a balance between increased cost to ratepayers and a decrease in the cost of debt for CL&P.

The Parties offer a range of reasonableness for an allowed ROE, as determined by the expert witness for CL&P of 10.20% and the expert witness for the Office of Consumer Counsel (OCC) of 8.90%. In addition I am aware that CL&P is a distribution only electric utility and as such does not have the risks associated with the generation component of integrated utilities. Since CL&P is a distribution only electric utility it is most closely risk comparable to other distribution only electric companies. Therefore I believe a 9.48% allowed ROE is reasonable which falls within the range of reasonableness of 8.90% and 10.20% established by the expert witnesses in this proceeding.

I believe this 9.48% allowed ROE will lower CL&P's cost of debt by maintaining the A- credit rating of CL&P. I find that this 9.48% ROE should produce operating income sufficient for CL&P to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

Submitted by:

Comissioner John W. Betkoksi, III
Vice Chairman
Public Utilities Regulatory Authority

#39 million final rate increase (7.8%) RB p.8

BEFORE THE PUBLIC SERVICE COMMISSION
OF
THE STATE OF MISSISSIPPI

12-3-2001

MISSISSIPPI POWER COMPANY DOCKET NO. 01-UN-0548

IN RE: NOTICE OF INTENT OF MISSISSIPPI POWER COMPANY TO CHANGE RATES FOR ELECTRIC SERVICE IN ITS CERTIFICATED AREAS IN THE TWENTY-THREE COUNTIES OF SOUTHEAST MISSISSIPPI

FINAL ORDER

COMES NOW, the Mississippi Public Service Commission (Commission) and issues the following Final Order in this cause.

I. INTRODUCTION

MPCo is a public utility as defined in Section 77-3-3(d)(i) of the *Mississippi Code of 1972, as amended*, and is engaged in the business of generating, transmitting and distributing electric power to and for the public for compensation in twenty-three (23) counties of southeast Mississippi, having its principal place of business at Gulfport, Mississippi. The Company's mailing address is Post Office Box 4079, Gulfport, Mississippi, 39502-4079.

MPCo is the holder of a Certificate of Public Convenience and Necessity issued in Docket No. U-99, as supplemented from time to time, authorizing its operations in specified areas of the twenty-three (23) counties of southeast Mississippi and is rendering electric service in accordance with its service rules and regulations and in accordance with schedules of rates and charges, all of which are a part of its tariff that has been previously approved by order of this Commission.

MPCo is a Mississippi corporation. A copy of its corporate charter, articles of incorporation, the names and addresses of its board of directors and officers, and the name of all persons owning fifteen percent (15%) or more of its stock are on file with this Commission.

MPCo has, since 1986, operated under a Performance Evaluation Plan Rate Schedule designated variously, as revised and amended from time to time, as PEP, PEP-1, PEP-1A and PEP-2. MPCo is authorized under PEP-2 to file a rate proceeding to adjust its rates when there is major construction, purchase, or modification of plant such as occurred with the new Victor J. Daniel Generating Plant Units 3 and 4, the construction of which were authorized by this Commission in Docket No. 97-UA-496. The units were placed in service in May and April of this year, respectively.

II. PROCEDURAL HISTORY

On August 3, 2001, pursuant to PEP-2, Mississippi Power Company, Inc. (MPCo) filed its Notice of Intent ("Notice") to change its rates for electric service, presently on file with the Commission, to be effective with the first billing cycle of January 2002, for bills rendered on and after such date. In its notice, MPCo requested an increase in rates of approximately 9.5% for the average retail customer.

The Commission entered a suspension order in this docket on August 3, 2001, requesting the Public Utilities Staff (Staff) to conduct a full investigation of the lawfulness of the proposed rates and charges contained in MPCo's notice. On August 7, 2001, the Commission issued an order suspending PEP-2 (Docket 93-UA-302) until a final order was issued in the proceeding at hand or until further Order of the Commission.

Notice of the filing was given as required by law and this Commission's Public Utilities Rules of Practice and Procedure ("Rules") to all persons who were parties of record in the

Company's last proceeding in which a major change in rates was sought, to certain other interested persons, and by publication on August 8, 2001, in the *Clarion Ledger* and in the *Sun Herald.*

A Scheduling Order was issued on August 14, 2001, establishing procedures for the timely resolution of this matter within the 120 day period prescribed by Mississippi law, including establishing intervention procedures, discovery procedures, deadlines for the filing of testimony, pre-hearing conferences, and setting his matter for hearing November 7-9, 2001.

The Intervenors in this filing were: Colonial Pipeline Company ("Colonial"); Mississippi Manufacturers Association ("MMA"); Federal Executive Agencies, by and through the Department of the Navy ("NAVY"); Williams Energy Marketing and Trading Company ("Williams"); Mississippi Casino Operators Association d/b/a Gulf Coast Gaming Association ("GCGA"); Mississippi Chapter of the National Federation of Independent Business ("NFIB"); Sierra Club, Mississippi Chapter ("Sierra"); Dynegy, Inc. ("Dynegy"); and Chevron USA, Inc. ("Chevron"). Colonial withdraw its intervention on November 6, 2001. The Staff participated as a party litigant. Each intervenor had a full opportunity for discovery in the period established in the Scheduling Order.

The Commission's Scheduling Order provided that all data requests were to be propounded no later than September 28, 2001. During the discovery phase of this proceeding, various parties propounded to MPCo approximately 420 data requests, which included sub-parts amounting to more than 1000 requests, covering all aspects of MPCo's filing and its operations. The Staff propounded 195 data requests, GCGA propounded 210 data request, MMA propounded 14 data requests and the Navy propounded 1 data request. No motion was filed with

the Commission by any party as to the sufficiency of the responses provided by MPCo or any other party.

MPCo requested a waiver of the requirements of Miss. Code Ann., Section 77-3-37(4) (2000). On August 24, 2001, GCGA filed a Motion in Opposition to MPCo's request for waiver of these requirements. On September 18, 2001, MPCo renewed its request for waiver of the requirements of Miss. Code Ann., 77-3-37(4) (2000). MPCo filed a lead-lag study on September 18, 2001.

A pre-hearing conference, scheduled by order of this Commission, was convened on October 18, 2001, in the hearing room of the Commission. The Honorable Bruce McKinley was designated by the Commission to conduct the hearing. All of the intervenors in this docket, except the Navy and NFIB, appeared and participated in the pre-hearing conference along with the Staff and MPCo. At the pre-hearing conference, discussions and information were exchanged by and among the parties in attendance. At the recommendation of Mr. McKinley and by agreement of the parties in attendance, the pre-hearing conference was recessed until November 6, 2001 at 9:00 a.m. (CST). However, the parties were encouraged by Mr. McKinley as authorized by law to enter into stipulations notwithstanding the fact that the original pre-hearing conference was recessed. On October 26, 2001, the Staff and MPCo entered into a Stipulation. The pre-hearing conference was not reconvened on November 6, 2001, after the parties acknowledged that no additional stipulations had been reached between any other parties.

Sierra pre-filed the direct testimony of Becky Gillete and Aaron Viles on October 18, 2001. the Navy pre-filed the direct testimony of Dr. John B. Legler, MMA pre-filed the direct testimony of R.G. McBride and Roland Woodard, GCGA pre-filed the direct testimony of James

R. Dittmer, and the Staff pre-filed the direct testimony of Dr. Christopher Garbacz on October 22, 2001.

On October 26, 2001, the Staff and MPCo filed a Stipulation in this docket addressing various issues presented in the Company's filing. Among other things, the Staff and Company stipulated that the Company's filing was made pursuant to the authority of PEP-2; that the Company's filing satisfied the filing requirements of Mississippi law and this Commission's Rules; that the Company's jurisdictional cost of service allocations are just and reasonable; that adjustments and/or reductions should be made to the Company's test year rate base and expenses; that the Company's test year capital structure and weighted cost of Debt, Trust Preferred Stock and Preferred Stock portions of cost of capital are appropriate, just and reasonable; that certain changes to PEP-2 are desirable; that the Company's request in this docket, as modified by the Stipulation should be approved; and that the changes to PEP-2 proposed in the Stipulation would result in the performance evaluation plan reflecting and producing rates that are just, reasonable, and in the best interest of the customers and the Company. The particular provisions of the Stipulation related to rate base and expense adjustments, cost of capital, and the refinements to PEP-2, and this Commission's findings with respect to those matters so stipulated are addressed in the Findings and Conclusions section of this Order.

On October 30, 2001, this Commission issued an order, *sua sponte*, which recognized the need for incorporating the findings and conclusions of this docket into PEP-2 and that such incorporation would allow for the orderly transition from rate case back to the normal operation of the PEP-2 rate. The order further authorized and directed the parties of record to submit such additional testimony or evidence as they deemed appropriate to address any issues raised by the

incorporation of the rate case conclusions into PEP-2 and by the re-activation of periodic evaluations under PEP-2. In response to this Commission's October 30 order, GCGA filed a motion asking this Commission to withdraw or modify that order. Oral arguments on GCGA's motion were held on November 6, 2001, at which time counsel for GCGA, MPCo, MMA and MPUS appeared and presented arguments regarding GCGA's motion and this Commission's October 30th order. That motion was overruled by the Commission.

On November 6, 2001, the Commission issued a Procedural Order establishing the procedures, including the order of presentation of witnesses and cross-examination for the upcoming hearings.

On November 6, 2001, the Staff filed supplemental testimony of Dr. Christopher Garbacz and MPCo filed supplemental testimony of Dr. Roger A. Morin, along with rebuttal testimony of H.E. Blakeslee, Frances Turnage and Charles a. Benore in accordance with the Commission's October 30, 2001 Order.

III. JURISDICTION AND SUFFICIENCY OF THE FILING

This Commission has jurisdiction of this matter by virtue of its subject and the authority conferred upon this Commission by the laws of the State of Mississippi.

This Commission finds that the pleadings, testimony, data, documentation and exhibits to this docket filed by MPCo comply with all the statutory filing requirements and the requirements of the Commission's Rules for major changes in rates in excess of $15 million, except the requirements of Miss. Code Ann. 77-3-37(4) (b), (c) and (d) (2000), which this Commission finds inapplicable and hereby waives.

This Commission further finds that the Stipulation entered into between the Staff and the Company and filed with this Commission complies with this Commission's Rules and Mississippi law.

Hearings in his docket were held on November 7-9, 2001 in the hearing room of the Commission.

IV. FINDINGS AND CONCLUSIONS

A. STIPULATION.

As stated previously, on October 26, 2001, the Staff and Company filed a joint Stipulation addressing numerous issues related to the Company's filing, including the incorporation of those agreements into PEP-2. As part of its investigation of this request, the Staff undertook a careful and thorough examination of the Company and its business operations. The Staff propounded and the Company responded to 195 data requests, many of which had multiple subparts. The Staff also reviewed the Company's responses to other parties' data requests. Additionally, the Staff had the benefit of conducting regular audits and reviewing the Company's books and records in connection with PEP and other rate filings. This experience gives the Staff a unique insight into the Company's finances and operations. Based upon the Staff's review, it entered into the Stipulation. The Staff recommended approval of the Company's request subject to several changes. This Commission has carefully reviewed the Stipulation and finds that there is substantial evidence in the record to support the Stipulation. This Commission finds that the Stipulation and the matters contained therein are just and reasonable, will benefit retail customers and will reduce the impacts of the Company's request on such customers. Therefore, this Commission hereby adopts the Stipulation dated October 26, 2001, and incorporates the Stipulation herein by reference. Specific findings regarding certain

Stipulation recommendations will be addressed later in this order, including findings regarding recommendations by intervenors which are contrary to the terms of the Stipulation.

1. **Jurisdictional Allocations.**

As noted in the Stipulation, the Company's proposed change in rates is based upon a jurisdictional cost of service study. This study was offered by Ms. Donna H. Van Loon. After careful review of the study and its allocations, the Staff and MPCo stipulated, and this Commission specifically finds, that the study and its jurisdictional allocations of expenses, revenues and rate base are just and reasonable and shall be used in this proceeding and other proceedings where such allocations must be made.

2. **Rate Base Items.**

The Company's filing also contains information related to the Company's rate base, revenue, and expenses for the historic year, 2000, as well as projections of rate base, revenues, expenses and cost of capital for the pro forma test year, 2002. That information was presented in the pre-filed testimony and exhibits of Ms. Van Loon, Ms. Frances Turnage, and Mr. Charles Benore.

The Company filed and proposed a retail average rate base of $753,184,879, for the pro forma test year. The Staff recommended a reduction of $21,435,744 to the Company's pro forma retail average rate base. With that adjustment, the Staff and Company have stipulated to an adjusted rate base of $731,749,135 for the pro forma test year, which this Commission finds to be just and reasonable and hereby adopts.

The Stipulation made specific recommendations regarding the treatment of certain rate base items:

a. Cash Working Capital: In its original filing, the Company calculated a value for cash working capital by taking one-eighth of its non-fuel operation and maintenance expense. This formula is commonly referred to as the "45-day formula." The 45-day formula resulted in a retail cash working capital calculation of $22,593,980. The Company later filed a lead/lag study that indicated a cash working capital calculation of $14,030,903. PEP-2 includes a cash working capital value of negative $5,500,000. The Staff and Company agreed and stipulated to the use of a $0 (zero) retail cash working capital value. Mr. Dittmer, a witness for GCGA, in his testimony adjusted the Company's lead-lag study to eliminate non-cash items. His calculation indicated that the Company's cash working capital requirements are approximately $638,729. Mr. Dittmer then suggested that cash working capital be set at a negative number, but those suggestions were not based on any substantial evidence. No other intervenor gave a recommendation or opinion on this issue. This Commission recognizes that determining the proper amount of cash working capital is not susceptible to exact measurement, but the preponderance of evidence offered indicates that the Company's cash working capital is greater than zero. Therefore, this Commission finds, based upon the various amounts calculated by the parties, that the stipulated retail cash working capital value of $0 (zero) is appropriate and is adopted for inclusion.

b. Construction Work in Progress: In its original filing, the Company proposed that 100% of the Company's average balance of construction work in progress ("CWIP") be included in rate base. The Company asserts that an on-going construction program is required to meet its customers' needs for reliable service. The Staff and Company have agreed and stipulated that the Company's average CWIP balance for all projects ending within one year of the end of the test period shall be included in rate base with any related allowance for funds used during construction ("AFUDC") accrued by the Company included in operating income. Mr. Dittmer

was the only other witness to address this issue. He testified and proposed that this Commission change its long-standing position on construction work in progress by not allowing any construction work in progress to be included in rate base. Mr. Dittmer suggests that the Company will be compensated appropriately by virtue of its use of AFUDC. However, this Commission finds that an on-going construction program is necessary for Mississippi Power Company to meet the needs of its customers, particularly in light of our emphasis on improving reliability and customer service. Moreover, this Commission agrees with Ms. Turnage that greater use of AFUDC could ultimately lead to higher costs for customers. Therefore, this Commission finds that the Staff's and Company's stipulated position on construction work in progress is appropriate and is adopted for inclusion.

c. Regulatory Asset Over/Under Recovery of Ad Valorem Taxes: For purposes of determining operating income and rate levels in PEP-2, the Company accrues its ad valorem tax expense throughout the year for which the tax assessment is made. A portion of ad valorem tax expense is recovered during that year in base rates. The remainder is collected the following year, after the taxes are paid, through the operation of the ad valorem tax adjustment clause (ATA). Because rate base and assessed property values increase over time and because of the mechanics of ATA, this balance is a growing under-recovery. The deferred amount (ad valorem tax under-recovery) has grown over the years to a projected average balance of over $8 million. This represents a substantial commitment of capital. The Staff and Company have stipulated and this Commission agrees and finds that it is appropriate to include the amount of this under-recovery in the determination of retail average rate base. No intervenor has objected to or proposed an alternate treatment of this regulatory asset.

d. Property Damage Reserve: This Commission has allowed the Company to accrue a storm damage reserve (a.k.a. property damage reserve) to prepare for the damages caused by natural disasters that occasionally affect the Company's facilities. Recently, this Commission issued an order in Docket No. 99-UN-497 that provides the Company with flexibility to adjust its accrual amount as the Company deems appropriate up to $4.5 million. The Company and Staff have agreed and stipulated that, as part of the adjustments to rate base, the Company would modify downward the amount for storm damage reserve expense accrual in its rate calculation for the test period and that the Company should continue to comply with this Commission's storm damage reserve order. This Commission finds that the reduction of the storm damage reserve accrual in the test year and the continued compliance with this Commission's order is just and reasonable.

3. Revenues and Operating Expense Items.

a. Adjustments to Expenses: The Company filed and proposed projected revenues and projected expenses which would result in retail net operating income of $76,034,767 in the 2002 test year. The Staff carefully reviewed and considered the Company's testimony and exhibits as they relate to various expense items. The Staff, as stated in the Stipulation, has carefully considered all of the information provided to the Staff and to other intervenors in response to all data requests in this proceeding, particularly with regard to the information provided on the Company's estimations of expenses for the Company's retail electric operations. The Staff has recommended, and Company has agreed, to a reduction in the Company's projected expenses in 2002 of $865,563, including the effect of income taxes. Mr. Dittmer was the only witness who suggested specific recommendations for adjustments to the Company's expenses, including recommendations to adjust outage expenses, labor expenses, capacity

equalization calculations, and revenues for off-system sales. However, some of the adjustments proposed by Mr. Dittmer were not based upon substantial evidence and others were based on incorrect assumptions. First, Mr. Dittmer recommended that this Commission reduce outage expenses at generating units by approximately $2.2 million in retail expenses in the test year based upon his normalizing those major outage expenses for a five-year average. However, the Company correctly pointed out that Mr. Dittmer's adjustment focuses on only the production component of the Company's total operations and maintenance cost. We are not persuaded by Mr. Dittmer's selective adjustment to the Company's operations and maintenance expenses. This Commission must consider all of the Company's operations and maintenance expenses to determine if the overall expenses are reasonable. When viewed in their totality, the Company's operations and maintenance expenses, as adjusted by the Stipulation, are reasonable.

Second, Mr. Dittmer recommended that this Commission eliminate from the Company's projected expenses the costs of establishing a Regional Transmission Organization ("RTO"). This Commission is well aware of the Federal Energy Regulatory Commission's recent attempts to form RTOs. If Southern Company and its operating companies are required to begin the process of forming an RTO in 2002, which is very likely based upon our own involvement in that process and based upon the testimony of Mr. Blakeslee, the Company's projected $1 million probably understates the actual costs to MPCo's retail operations in 2002.

Third, Mr. Dittmer proposed an adjustment to payroll/labor costs in 2002. The Company's witness, Ms. Turnage, addressed Mr. Dittmer's proposal and demonstrated that the Company's filed labor costs are just and reasonable. Therefore, this Commission rejects Mr. Dittmer's proposal to reduce labor costs.

This Commission has long encouraged the parties to try to resolve all reasonable issues, and for this reason, this Commission requires that pre-hearing conferences be held in these cases. Several witnesses indicated that the adjustment to expenses was a "settlement" of disputed issues related to expenses. This Commission realizes that the Staff and utilities routinely disagree over the treatment of expense items, and finds that the adjustment agreed to in the Stipulation is reasonable in light of the extensive knowledge the Staff has regarding the Company's operations and the overwhelming amount of discovery produced by the Company in this proceeding.

The Staff will again have the opportunity to review the Company's 2002 expenses and to propose adjustments to those expenses in connection with the Company's PEP-2 evaluation for the twelve-month period ending December 31, 2002. This evaluation will review twelve months of historical or actual expense information, which is the same period as the projected period in this filing which was prepared using projected 2002 figures. For the foregoing reasons and based upon this Commission's treatment of the specific adjustments suggested by Mr. Dittmer, this Commission finds that the proposed expenses as adjusted by the Stipulation are just and reasonable and, when considered along with the other findings of this Commission, will result in just and reasonable rates and we hereby adopt same.

b. Adjustments to Revenues: Mr. Dittmer recommends that this Commission make an adjustment to the Company's projected off-system sales revenues for 2002. Mr. Dittmer proposes to increase the projected revenues from off-system sales by approximately $8.1 million. Mr. Dittmer admitted however, that his adjustment was based upon the assumption that the Company should be in a better position to sell capacity off-system in 2002 than it was in 2001. Mr. Dittmer apparently did not consider the fact that the Company had been purchasing significant amounts of capacity and energy prior to the completion of Daniel Units 3 and 4, and

that these purchases were replaced by those units. Mr. Dittmer did not undertake any evaluation of market conditions and prices upon which he could base such an adjustment to the Company's projections. His proposed adjustment to off-system sales is therefore speculative and is not adopted.

Mr. Dittmer also recommends an adjustment to increase the revenues to MPCo associated with capacity equalization payments under the Intercompany Interchange Contract ("IIC"). Again, Mr. Dittmer admits that his recommendation is based upon assumptions (without any factual basis about the IIC capacity reserve sharing calculations.) In the Company's rebuttal testimony, Ms. Turnage demonstrated that Mr. Dittmer's calculations were flawed, that he overstated available capacity and that he gave no weight to the seasonal differences in the value of capacity as provided in the IIC and as shown in response to data requests on this issue. This adjustment is not adopted.

4. **Capital Structure and Cost of Capital.**

This Commission has reviewed the portions of the Stipulation agreeing to the Company's proposed capital structure and the weighted cost of the Debt, Trust Preferred Stock and Preferred Stock. This Commission adopts this portion of the Stipulation and finds that all of the elements of MPCo's proposed cost of capital, except for the Company's proposed rate of return on common stock equity, which will be considered separately, are just and reasonable and should be approved. The only other testimony was the recommendation of Dr. John Legler, the expert witness for the Navy, who testified that an average of the 2000 and 2002 year end equity/debt ratio should be utilized for the test period rather than a year-end equity/debt ratio. While we agree that there may be some merit for using an average capital structure, the average should be developed using the beginning and ending of the projected test period – December 2001 and

December 2002 – and not year end 2000 and 2002. It should also be remembered that year 2000 is prior to the time of the equity infusion for the new units. This Commission is not persuaded by Dr. Legler and finds that the stipulated year-end equity/debt ratio, which is a requirement of PEP-2 previously approved by this Commission, is appropriate for use in this case. Since this filing and its results are to be considered in light of PEP-2 and will become a part of PEP-2, it is important that, where appropriate, the findings of this order should be consistent with PEP-2.

B. RETURN ON COMMON STOCK EQUITY.

This Commission heard a great deal of testimony regarding the Company's return on common stock equity, since a part of the Company's request for rate relief is related to an increase in its cost of capital – specifically, the cost of common stock equity. The Company asserts that the existing formulas for return on equity in PEP do not reflect current conditions in the financial markets and therefore do not produce an adequate return to investors. Three persons offered testimony regarding return on common equity – Mr. Charles Benore, Dr. John Legler, and Dr. Chris Garbacz. It is important to note that each of the three cost of capital witnesses testified to and supported a recommended rate of return, a range of returns which they considered reasonable and certain formulas or models used to develop those values. In each case, the formulas or models used differ from the current formulas in the PEP plan. We have carefully considered all of the information presented, and have spent considerable time and effort evaluating that information. This information should be considered to determine a return on the common stock equity for MPCo that is just and reasonable and consistent with companies of comparable risk; that complies with the Mississippi Public Utility Act and the Rules and Regulations of this Commission; and that complies with the requirements of the United States Supreme Court rulings in *Bluefield Water Works & Development Co. v. Public Service*

Commission of West Virginia, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

1. **Benore Testimony.**

Mr. Charles Benore testified for MPCo and recommended a 13.25% return on common equity. Mr. Benore used four models in arriving at a proposed rate of return on common equity for MPCo. Those four models are the Discounted Cash Flow Model ("DCF"), the Equity Risk Premium Model ("ERP"), an average of the standard Capital Asset Pricing Model ("CAPM") and the Empirical Capital Asset Pricing Model ("ECAPM"), and the "Comparable Earnings" Method. Mr. Benore's testimony provides descriptions of the DCF, ERP and CAPM models, as does the testimony of the other witnesses. The results of the first three market models were transformed by Mr. Benore in a process described below. Mr. Benore's fourth model, a "Comparable Earnings" Method, is also discussed below. For his DCF and CAPM models and his "Comparable Earnings" method, Mr. Benore selected comparable companies using nine (9) criteria or tests intended to assure that the companies used in these formulas were comparable to MPCo as to important matters such as risk. Mr. Benore testified that MPCo should be allowed a rate of return on common equity of 13.25%, including Transformation and Comparable Earnings, both of which are discussed below.

Mr. Benore's testimony included a calculation of return on common equity which used the same formulas considered by Dr. Garbacz - the DCF, ERP and CAPM (both standard and empirical averaged). Using these formulas in a manner similar to that used by Dr. Garbacz (without Transformation or the "Comparable Earnings" method), Mr. Benore's formulas on average resulted in a return on common equity of 11.47%.

Mr. Benore also used a fourth model, the "Comparable Earnings" method, which calculates a return on common stock equity for MPCo based on the earnings of comparable companies. This model is likewise described in Mr. Benore's testimony. This comparable earnings test or method was criticized by Dr. Garbacz, who testified that the companies were not truly comparable in his opinion, and further because it compared the retail earnings of MPCo with the total earnings of the other companies, which included wholesale and unregulated earnings. This test determined a return on equity for MPCo of 13.3%.

Mr. Benore further testified that the results of the DCF, ERP and the average of the CAPM models should be adjusted by a process called transformation. Transformation, according to Mr. Benore's direct testimony, "is the process that determines the necessary regulatory book return so that investors have an opportunity to earn their required market return." According to Mr. Benore, the standard models for regulatory book return do not provide the return required by investors when the ratio of market value to book value of common stock is above one (1). This Commission desires that companies under its regulatory control remain healthy and earn a return that allows them to attract the capital needed to provide the quality of service that we and their customers require of them. The argument presented was that transformation has not been accepted in any other regulatory rate proceeding. Since we cannot determine any other commission that has endorsed transformation, we are not able to accept this theory at this time.

2. Legler Testimony.

The second rate of return witness heard by this Commission was Dr. John Legler, on behalf of the Navy. Dr. Legler testified that he found a range between 10.5% and 11.5%, which would produce a just and reasonable return on equity for MPCo. His recommended return was

11.0%. In his rebuttal testimony, Mr. Benore noted several errors in Dr. Legler's calculations: an improper retention growth rate estimate for FPL Group, failure to add 0.5% to the growth rate for each of his comparable companies, and the use of August 31, 2001 prices instead of September 28, 2001 prices. Dr. Legler agreed on cross-examination that he had made errors in his direct testimony and when those errors are corrected and considered, Dr. Legler's Late Filed Exhibit____(JBL-1) Schedule 2 (Revised) indicates that his calculated return on equity would become 11.25% using an average of the models used. In response to questions on cross-examination, Dr. Legler gave an opinion that a range from 10.3% to 12.17% would result in a reasonable return. Dr. Legler used three (3) models to calculate his recommended return - DCF, ERP, and CAPM.

3. **Garbacz Testimony.**

The third rate of return witness testifying before this Commission was Dr. Chris Garbacz, on behalf of the Staff. In his pre-filed direct testimony, Dr. Garbacz determined a recommended rate of return of 11.45% for MPCo's return on common stock equity, using three (3) models -- DCF, ERP and CAPM (both standard and empirical averaged). The models applied by Dr. Garbacz and Mr. Benore were virtually identical. In rebuttal testimony, MPCo's expert witness, Mr. Benore, pointed out three errors in Dr. Garbacz's analysis. These errors were that Dr. Garbacz (1) failed to adjust the dividend to be received by investors to the first holding year as required by the DCF model, (2) failed to adjust the ERP and CAPM for flotation costs and only adjusted the DCF model, and (3) did not use the same time period for interest rates for the Equity Risk Premium and CAPM models as used for stock prices. Dr. Garbacz accepted the first two (2) of the three (3) corrections, which results in increasing his recommended return from 11.45%

to 11.67%. Dr. Garbacz then reduced his recommended return to 11.44% to reflect his claim that MPCo is less risky.

4. **Summary of Rate of Return Witnesses.**

Mr. Benore's range of reasonable returns for MPCo (without transformation or comparable earnings tests) is between 11.4% and 11.5%; Dr. Legler's range, as testified on cross-examination, is between 10.30% and 12.17%; and Dr. Garbacz's range, as corrected is between 11.22% to 11.67%, adjusted under PEP. As Dr. Legler stated on cross-examination, any rate of return selected by this Commission within these ranges would be reasonable. However, it also is obvious from studying these ranges of reasonable returns that the preponderance of the testimony would require a return in the 11.4% to 11.7% range, and that a rate of return in that range would result in just and reasonable rates for MPCo and its customers.

5. **Finding of Rate of Return.**

After considering and carefully analyzing all of the rate of return testimony and considering our experience with rate making, including both conventional and formula-type rate of return plans previously approved by this Commission, we find that a just and reasonable rate of return on common stock equity to be used as part of determining just and reasonable rates for MPCo's customers should be set at 11.5%. This rate of return is based upon the models and the substantial weight of the credible evidence and provides reasonable rates for the customers of MPCo and a fair return for the Company. We find that this rate would be equitable, just and reasonable for use in both a conventional rate case and for use in conjunction with a performance review and analysis under PEP-2.

C. PEP-2 CONSIDERATIONS.

Rate schedule PEP-2 and its predecessors have been the rate approved for setting the revenues of the Company since 1986. At the time PEP was first adopted, this Commission recognized the need to alter the conventional method of rate making to consider and adjust for the Company's performance in meeting the most important needs of its customers. The conventional rate setting process did not take into consideration the Company's performance or set rates based upon that performance. To provide for more emphasis on the needs of utility customers in Mississippi, this Commission in 1985 ordered the Company to develop and file a performance-based rate mechanism. After extensive review and deliberation, the PEP plan was adopted. This plan has allowed the Company the flexibility to balance competing priorities, to access capital necessary to construct and maintain facilities, to provide services needed by customers and, most importantly, to do all of these at rates which have been and are low in comparison to other utilities. Since then, this Commission has ordered most of the larger utilities under its regulatory authority to adopt similar performance-based ratemaking plans.

The history and lawfulness of the Company's performance evaluation plan is well settled under Mississippi law. This Commission agrees with the Staff and Company that PEP-2 constitutes a "formula type rate of return evaluation rate" under the provisions of Miss. Code Ann. 77-3-2 (2000). That section provides this Commission the authority for the adoption of and administration of formula type rate plans and authorizes the periodic calculation, review, and adjustment of revenues, performance, and rates of return.

The Company's retail rate mechanism PEP-2 was in effect at the time of the Company's filing of its notice of intent in this docket. Rate PEP-2 provides the basis for determining the just and reasonable revenue needs of MPCo and for fixing its rates. PEP-2 also includes a section

entitled "Major Plant Addition or Modifications," which provides for changes in rates under PEP-2 when major new plant is added. MPCo's filing herein is pursuant to and authorized by this section of PEP-2.

The Staff and Company also jointly acknowledge, and this Commission concurs, that the construction of the Company's new combined cycle units at Victor J. Daniel Electric Generating Plant Units 3 and 4 constitute a major plant addition as contemplated by PEP-2, and that the Company's filing is authorized under PEP-2.

At the time that the Company filed this rate request under the "Major Plant Additions or Modifications" section of PEP-2, this Commission suspended the regular semiannual evaluations. The Staff and Company have stipulated, and this Commission concurs, that the Company should return to regular periodic PEP-2 evaluations at the end of 2002.

One object of the PEP plan is to promote rate stability. A key provision of PEP-2 limits rate changes resulting from regular semiannual evaluations to 2% of aggregate retail revenue. In order to return to normal operation of PEP and maintain rate stability, it is essential that, in deciding the rate request before us in this docket, the Commission also consider the ongoing operation of PEP-2 and make provision for appropriate integration of this decision with the ongoing operation of the PEP-2 plan.

In recognition of this, on October 30, 2001, this Commission ordered that all parties present such testimony as it deemed appropriate concerning the incorporation of the holding in this docket with and into PEP-2. This was done to recognize and allow for the orderly transition of this case to the normal and continued operations of PEP-2. In order to accomplish the integration of this proceeding with PEP-2 it is necessary for us to:

a. Include into PEP-2 the approved changes in this docket that are necessary to

update and improve PEP-2 and to assure that PEP-2 continues to yield just and reasonable rates, and

b. Provide the means and requirements necessary to integrate the results of this case with the remaining provisions of PEP-2, which continues to be rate making mechanism for determining the Company's rates.

1. **Changes Necessary in PEP-2**

The Staff and the Company have stipulated to the following matters regarding PEP-2:

a. Future rate adjustments under PEP-2 should be determined based upon the middle of the Range of No Change, not on the top or bottom of the Range; and the "sharing" of rate increases and decreases based on price performance should be eliminated. An additional penalty/reward mechanism should be added as per the Stipulation.

b. The cash working capital value used in PEP-2 should be $0 (zero).

c. The CWIP in PEP-2 should include all projects ending within a year of the end of the evaluation period, with any related AFUDC included in operating income.

d. The Company's rate base in PEP-2 should include the regulatory asset Over/Under Recovery of Ad Valorem Taxes.

e. The following language should be added to Rate Schedule, "PEP-2" MPSC Schedule No. 28, page 3 of 28, under the section Filing Procedures:

> In considering any evaluation filed pursuant to this Rate PEP-2, nothing in this Rate shall be construed to prevent the Staff from disputing the accuracy of any investment, revenue or expense; from disputing that any investment, revenue or expense is prudent in amount or purpose or otherwise in accord with the Mississippi law, the Rules and Regulations of the Commission or this Rate PEP-2; or from disputing whether any item investment, revenue or expense is improperly recorded to an account. The Staff may request and the Company shall provide clarification and additional data underlying the entries subjacent to the categories of (1) Investment, (2) Revenues, and (3) Expenses.

f. The Company's initial evaluation under PEP-2, as revised pursuant to this Stipulation in this docket, should be made in February 2003, in accordance with the rate schedule based upon the twelve months ended December 31, 2002.

The Commission finds that the changes to PEP-2 proposed by the Stipulation will produce rates which, when combined with the other findings of this order, will be just, reasonable and in the best interest of the Company's customers and the Company, and we hereby adopt those changes for incorporation in PEP-2.

The Stipulation does not include any agreements regarding the calculation for the cost of common stock equity in PEP-2 (and specifically as to the models included for the calculation of K_{AVG}% therein), which is currently provided in Appendix C of that rate schedule.

There was testimony by some of the parties as to (1) whether the rate of return on common stock equity for a conventional case should become the K_{AVG} in PEP-2 (known previously as the benchmark) and, therefore, should be adjusted – up or down – for MPCo's performance or (2) whether the conventional rate of return should be the allowed return under PEP-2 including performance. This Commission is familiar with PEP-2 and its predecessors. We have never questioned that the conventional return on equity should be the benchmark or starting point (K_{AVG}) with adjustments to be made for performance according to the PEP rate schedule. We agree with witness Dr. Roger Morin that this is what was intended in the initial PEP and all subsequent changes to PEP.

This commission finds, based on the testimony of all the rate of return witnesses, that the present models used in PEP-2 may not currently produce a return on common stock equity (or K_{AVG} as it is referred to in PEP-2) which is just and reasonable.

This Commission is of the opinion that changes to the current models used in PEP-2 should be considered in a separate docket, and that the parties in this proceeding and any new intervenors should be given further opportunity to comment and offer testimony as to changes in the formulas. In order to accomplish this review and to assure that the models provide just and reasonable returns to the Company and likewise just and reasonable rates for MPCo's customers when the semi-annual evaluation under PEP-2 are reinstituted, we are simultaneously with the issuance of this order, issuing a Show Cause Order to MPCo which will establish a new docket to determine the sufficiency of the models which will be used to calculate a just and reasonable return on equity or K_{AVG} for PEP-2.

All of the changes made to PEP-2 by this order, including those adopted from the Stipulation, are subject to change at any time that this Commission finds that they or any other provisions of PEP-2 become unreasonable or cease to result in just and reasonable rates. As we have done in the past, including in this docket, we are not hesitant to call for and make any and all changes which might be necessary.

2. **Integration of the Findings in this Case with PEP-2.**

As this Commission has previously stated, PEP-2 continues to be the rate mechanism under which MPCo's revenue requirements are determined and changes in rates are made. PEP-2 in the Section entitled "Major Plant Additions or Modifications" allows for a change in rates that might be greater than the 2% limitation included in PEP-2, but does not eliminate any of the features of PEP-2. Since no filing under this section of PEP-2 (or any predecessor PEP) has heretofore been made or needed, this Commission feels a need to set forth the requirements and the results of a filing under that section.

The "Major Plant" section of PEP-2 requires that a filing for extraordinary relief due to

the construction of a generating plant must comply with the major case filing requirements provided for by the Public Utility Act and the rules and regulations of this Commission. This requires voluminous financial and other data which would not be filed under an ordinary evaluation under PEP-2. It also requires that a projected test year for determining rates be used instead of the historic test year used in the PEP-2 periodic evaluations. It allows for recovery of an increase in revenues in excess of the 2% of retail revenues, if such is justified.

Neither the "Major Plant" section nor any other section of PEP-2, eliminates the need to perform a calculation of performance to determine whether a change, up or down, should be made so as to reflect MPCo's performance. This is by design. This Commission has since 1985 required that MPCo's rates be adjusted for performance in those areas which most affect the customers -- currently price, reliability and customer satisfaction. We never intended that any rate for MPCo set under PEP-2 or any of its provisions ignore performance.

When this matter was filed, we did not void PEP-2 as the rate method for MPCo, we simply suspended the semi-annual rate evaluation to be made under it. This allowed us to litigate the matters required under the "Major Modification" section and to use the remaining provisions to determine just and reasonable rates for MPCo.

The use of a projected test year, as required here, evaluates MPCo for the year 2002. It would have been counter-productive to evaluate MPCo's need for rates under PEP-2 prior to the end of the 2002 test year. This was the reason we have concluded in accord with the Stipulation, that the semi-annual rate evaluations would only resume based on the historic 12 months ended December 31, 2002. This will also give this Commission a second evaluation, based on actual, historic data of the same period for which rates are to be made here on the projected 2002 year.

The procedure for the calculation of the Company's revenue requirements in this docket, which we find to be consistent with PEP-2, is as follows:

a. The rate base, revenues and expenses, capital structure, and weighted cost of debt, trust preferred stock and preferred stock included in the filing, as modified by the Stipulation and approved herein, shall be used.

b. The return on common equity, as determined herein and adjusted by .25% for flotation costs shall be used as K_{AVG} in the PEP-2 calculation, as PEP-2 is modified by the Stipulation, using the Company's performance as of December 31, 2000, as was used by Dr. Garbacz.

c. Based on this procedure, the Commission finds that the rates determined herein are just and reasonable.

The Company shall determine its revenue requirements for the test year on the basis of this order; shall allocate that revenue requirement to its rate schedules and special contracts; and shall file revised rate schedules reflecting the change.

Although not mentioned in the testimonies of the parties in this docket, the Company included in its test year expenses one-third of the total estimated amount of the costs it expected to incur in this docket. Beginning in 2002, the total costs incurred by MPCo in this docket shall be amortized over a period not to exceed 36 months.

This order shall be effective upon issuance.

Chairman Nielsen Cochran voted Aye; Vice-Chairman Michael Callahan voted Aye; Commissioner Bo Robinson voted Aye.

SO ORDERED by the Commission on this the 3rd day of December, 2001.

MISSISSIPPI PUBLIC SERVICE COMMISSION

Nielsen Cochran, Chairman

Michael Callahan, Vice Chairman

Bo Robinson, Commissioner

ATTEST: A True Copy

Brian U. Ray,
Executive Secretary

Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return

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I. Introduction

Shareholder required rates of return play key roles in establishing economic criteria for resource allocation in many corporate and regulatory decisions. Theory dictates that such returns should be forward-looking return requirements that take into account the risk of the specific equity investment.

Estimation of such returns, however, presents numerous and difficult problems. Although theory clearly calls for a forward-looking required return, investigators, lacking a superior alternative, often resort to averages of historical realizations. One primary example is the determination of equity required return as a "least risk" rate plus a risk premium where an equity risk premium is calculated as an average of past differences between equity returns and returns on debt instruments. The historical studies of Ibbotson *et al.* [9] have been used frequently to implement this approach.[1] Use of such historical risk premia assumes that past realizations are a good surrogate for future expectations and that risk premia are roughly constant over time. Additionally, the choice of a time period over which to average data under such a procedure is essentially arbitrary. Carleton and Lakonishok [3] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

Recently Brigham, Shome, and Vinson [2] surveyed work on developing *ex ante* equity risk premia with particular emphasis on regulated utilities. They presented their own risk premia estimates, which make use of financial analysts' forecasts as surrogates for investor expectations.

The current paper follows an approach similar to Brigham *et al.* and derives equity required returns and risk premia using publicly available expectational

Thanks go to Ed Bachmann, Rich Harjes, and Hamid Mehran for computational assistance and to Bill Carleton, Pete Crawford, and Steve Osborn for many discussions. I gratefully acknowledge financial support from the UNC Business Foundation and the Pogue Foundation and thank Bell Atlantic for supplying data for this project. Finally, I thank colleagues at UNC for their helpful comments.

[1] Many leading texts in financial management use such historical risk premia to estimate a market return. See for example, Brealey and Myers [1]. Often a market risk premium is adjusted for the observed relative risk of a stock.

data. The estimation makes use of dividend growth models but incorporates expected rather than historical growth rates. A consensus forecast of financial analysts is used as a proxy for investor expectations. While Brigham *et al.* focus on utility securities, this paper also provides estimates of risk premia for a broad market index. Equity risk premia for both the market and for utilities are shown to vary over time with changes in the perceived riskiness of corporate activity relative to U.S. government bonds. In addition, the estimated risk premia at any given time are shown to vary across groups of stocks. The paper also provides results using the dispersion of analysts' forecasts as an *ex ante* proxy for equity risk.

Section II discusses related literature on financial analysts' forecasts (FAF) and the estimation of required returns using such forecasts. In Section III models and data are discussed. Following a comparison of the results to those of earlier studies (including historical risk premia), the estimates are subjected to economic tests of both their time-series and their cross-sectional characteristics in Section V. Finally, conclusions are offered.

II. Background and Literature Review

In finance, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (*e.g.*, bonds or other equities) and the riskiness of the stock. To isolate the effects of risk it is often useful (both theoretically and empirically) to work in terms of a risk premium (rp), defined as

$$rp = k - i, \qquad (1)$$

where i = required return for a zero risk investment. Theoretically, i is a risk free rate, though empirically its proxy (*e.g.*, yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk.[2] While models such as the capital asset pricing model offer explicit methods for varying risk premia across securities, they provide little practical advice on establishing some benchmark market risk premium. Other models, such as the dividend growth model (hereafter referred to as the discounted cash flow, or DCF, model), can be used to provide direct estimates of k, and hence implied values of rp, but are silent on how rp ought to vary across firms. In this paper DCF models are used to establish risk premia both for the market and for utility stocks. Since the DCF analysis uses a consensus measure of FAF of earnings as a proxy for investor expectations, a brief review of research on FAF is appropriate.

A. Literature on FAF

Much of the burgeoning literature on properties of FAF is surveyed by Givoly and Lakonishok [8]. Of primary importance for this work is the relationship between FAF and investor expectations that determine stock prices. Such forecast data are readily available. That they are used by investors is evidenced by the commercial viability of services that provide such forecasts and by the results of studies of investors' behavior (Touche, Ross and Company [16], Stanley, Lewellen and Schlarbaum [15]). Moreover, a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average[3] of forecasts by individual analysts. Elton, Gruber, and Gultekin [5] show that stock prices react more to changes in analysts' forecasts of earnings than they do to changes in earnings themselves, suggesting the usefulness of FAF as a surrogate for market expectations. In an extensive NBER study using analysts' earnings forecasts, Cragg and Malkiel [4, p. 165] conclude "the expectations formed by Wall Street professionals get quickly and thoroughly impounded into the prices of securities. Implicitly, we have found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based." Updating Cragg and Malkiel's work, Vander Weide and Carleton [17] recently compare consensus FAF of earnings growth to 41 different historical growth measures.[4] They con-

[2]In this development the effects of tax codes and inflation on required returns are ignored.

[3]Mayshar [14] discusses the problems of explaining equilibrium prices of securities when there is divergence of opinion among investors. One issue is whether it is the expectation of the marginal investor or the average investor that determines security prices. Mayshar shows that, in general given divergence of opinion and trading costs, not all investors trade in all assets and that equilibrium prices and the identity of investors trading in each asset are jointly determined. In this sense, equilibrium prices can be considered as "determined simultaneously by the average and marginal investors."

[4]Both Cragg and Malkiel [4] and Vander Weide and Carleton [17] show that an average measure of analysts' forecasts of growth in earnings is powerful in explaining cross-sectional variation in price earnings ratios of stocks.

clude that "there is overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price . . . consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions." [17, p. 15].

B. Use of FAF to Estimate Equity Required Returns

Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements. Typically such approaches have estimated an *ex ante* risk premium (rp) calculated as the difference between required return and a least risk rate as shown in Equation (1).

Malkiel [13] estimated such risk premia for the Dow Jones Industrial Index using a nonconstant growth version of the DCF model. Initial years of growth were based on Value Line's five-year earnings growth forecasts with subsequent growth approaching a long-run real national growth rate of 4%. More recently, Brigham, Vinson, and Shome [2] used a two stage DCF growth model to estimate *ex ante* risk premia for electric utilities and the Dow Jones Industrial Index. For the period 1966–1984, they report annual risk premia for both Dow Jones Industrial and Electric Indices using Value Line's forecasts. Beginning in 1980 they report monthly risk premia for electric utilities with the source of FAF varying over time; starting with Value Line, adding Merrill Lynch and Salomon Brothers in 1981 and finally, in mid-1983, adding IBES data. IBES (Institutional Broker's Estimate System) is a collection of analysts' forecasts and is discussed in the next section. The resultant risk premia vary over time. In addition, Brigham *et al.* present evidence that their estimated risk premia vary cross-sectionally with a stock's risk (as proxied by bond rating) and over time with the level of interest rates. FAF also have been used in conjunction with DCF models by a number of expert witnesses in rate of return determination for regulated utilities. Recently, the Federal Communications Commission [6] tentatively endorsed the use of consensus FAF in DCF determinations of required return on equity.[5]

This paper adds to earlier work in a number of important respects. First, while Malkiel and Brigham *et al.* focus on electric utilities or the Dow Jones Industrial Index, this paper estimates risk premia for a broadly defined market index — the Standard and Poor's 500. Thus, the results are directly comparable to historical "market" risk premia typically estimated on a similar sample of stocks. Second, the study uses a large sample of FAF (beginning in 1982 when the necessary data first became available). This provides the ability to use a consensus measure of expectations as would be suggested by financial theory. Third, the results show that the derived risk premia change over time and that these changes are related to proxies for risk, which would be expected to be associated with equity risk premia. Although such changes have been noted by earlier studies (*e.g.*, Brigham *et al.*), there is little work explaining the patterns of change. Finally, the paper shows the usefulness of the dispersion of FAF as a proxy for risk. Such a measure is a direct expectational measure of risk and does not rely on assumptions of risk stability over time as do most operational methods of deriving risk surrogates.

III. Models and Data

A. Model for Estimation

The DCF model states that the current market price is the present value of expected future cash flows from ownership. The simplest and most commonly used version estimates shareholders' required rate of return, k, as the sum of dividend yield and expected growth in dividends, or

$$k = (D_1/P_0) + g, \qquad (2)$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[6] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expecta-

[5]In response to the FCC's *Notice of Proposed Rulemaking* [6] to determine authorized rates of return, AT&T used an approach driven by FAF growth estimates from IBES. Also see, for example, W.T. Carleton, *Testimony before the Vermont Public Service Board*, Docket No. 4865 (January 1984) and R.S. Harris, *Testimony filed with the Delaware Public Service Commission*, Docket 84–33 (November 1984). In its *Supplemental Notice* [6], the FCC tentatively endorsed substantial reliance on FAF for use in DCF determination of cost of equity.

[6]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon.

tions of future performance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties even if the simple version shown in Equation (2) fits the equity investment in question. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

Many analysts publish forecasts of corporate earnings. Such forecasts are widely disseminated and are the subject of considerable interest both to investors and researchers (see Givoly and Lakonishok [8]). In recent years, this interest has led to a viable market for services that collect and disseminate such FAF. FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm. Data in IBES represent a compilation of earnings per share (EPS) estimates of about 2000 individual analysts from 100 brokerage firms on over 2000 corporations. IBES data are provided to clients in a number of forms, including on-line data bases provided by vendors. The client base, which currently numbers more than 300, includes most large institutional investors such as pension funds, banks, and insurance companies. Representative of industry practice, IBES contains estimates of (i) EPS for the upcoming fiscal year, (ii) EPS for the subsequent year, and (iii) a projected five-year growth rate in EPS. Each item is available at monthly intervals.

IBES collection procedures are designed to obtain timely forecasts made on a consistent basis. IBES requests "normalized" five-year growth rates from analysts. Such normalization is designed to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. These growth and other earnings forecasts are updated when analysts formally change their stated predictions. IBES does, however, verify prior forecasts monthly to make sure that analysts still hold to them. Despite these procedures, there remain potential difficulties in using IBES data to the extent that some analysts fail to normalize growth projections or fail to continually review and revise their earnings estimates. To control for some of these potential difficulties, this analysis uses averages of analysts' forecasts for a wide range of companies over an extended number of months.

In this research, the mean value of individual analyst's forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[7] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. One could make alternate assumptions about growth after five years and use a more general version of a DCF model, but unfortunately, there is no source for obtaining market estimates of this expected growth. As a result, the current analysis applies the five-year growth rate as a proxy for g in Equation (2). Given no objective basis for predicting a change in growth (see Footnote 6), this avoids the introduction of *ad hoc* assumptions about future growth. Importantly, however, the approach is applied to portfolios of stocks rather than to individual securities, since future growth patterns may be expected to have drastic changes for some specific securities. Stock prices were obtained from Chase Econometrics and dividend and other firm-specific information from COMPUSTAT. Interest rates (both government and corporate) were gathered from Federal Reserve Bulletins and from Moody's Bond Record. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard and Poor's 500 stock (SP500) index plus approximately

Exhibit 1. Variable Definitions

k	=	equity required rate of return
P_0	=	average daily price per share*
D_1	=	expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1+g)$†
g	=	average financial analysts' forecasts of five-year growth rate in earnings per share (from IBES)
σ_g	=	cross-sectional standard deviation of analysts' forecasts of growth in earnings per share (from IBES)
N_g	=	number of analysts' forecasts of g (from IBES)
i_{20}	=	yield to maturity on 20-year U.S. government obligations. Source: Federal Reserve Bulletin, constant maturity series
i_c	=	yield to maturity on long-term corporate bonds: Moody's average
i_u	=	yield to maturity on long-term public utility bonds: Moody's average
rp	=	equity risk premium calculated as $rp = k - i_{20}$

*In results reported P_0 is the average daily price for a stock from the beginning of the month up to and including the date of publication of monthly IBES data (typically half a month). Almost identical results were found using the average price for the entire month.
†See Footnote 8 at the end of the paper for a discussion of the $(1+g)$ adjustment.

[7]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same. Vander Weide and Carleton [17] also use the IBES growth rate in earnings per share.

150 additional stocks of regulated companies. Since five-year growth rates were first available from IBES in January 1982, the analysis covers the 36-month period 1982–1984. On average, each company in SP500 had approximately nine individual forecasts of g per month, with some companies having 20 or more forecasts of g. As a result, well over 100,000 FAF (company-months) were employed in the analysis.

IV. Construction of Risk Premia and Required Rates of Return

For each month, a "market" required rate of return was calculated using each dividend paying stock in the SP500 index for which data were available. The DCF model in Equation (2) was applied to each stock and the results weighted by market value of equity to produce the market required return.[8] The return was converted to a risk premium by subtracting i_{20}, the yield to maturity on 20-year U.S. government bonds.[9] The procedure was repeated for the Standard and Poor's Utility Index (SPUT) of 40 stocks. Exhibit 2 reports the results by quarter.

Exhibit 2. Required Rates of Return and Risk Premia

		SP500		SPUT	
	Bond Yield*	Required† Return	Risk‡ Premium	Required† Return	Risk‡ Premium
1982					
Quarter 1	14.27	20.81	6.54	18.83	4.56
Quarter 2	13.74	20.68	6.94	18.51	4.77
Quarter 3	12.94	20.23	7.29	18.55	5.61
Quarter 4	10.72	18.58	7.86	17.20	6.48
Average	12.92	20.08	7.16	18.28	5.36
1983					
Quarter 1	10.87	18.07	7.20	16.71	5.84
Quarter 2	10.80	17.76	6.96	16.52	5.72
Quarter 3	11.79	17.90	6.11	16.39	4.60
Quarter 4	11.90	17.81	5.91	16.00	4.10
Average	11.34	17.88	6.54	16.41	5.07
1984					
Quarter 1	12.09	17.22	5.13	16.48	4.39
Quarter 2	13.21	17.42	4.21	16.99	3.78
Quarter 3	12.83	17.34	4.51	16.62	3.79
Quarter 4	11.78	17.05	5.27	15.18	4.04
Average	12.48	17.26	4.78	16.48	4.00
Average 1982–1984	12.25	18.41	6.16	17.06	4.81

*i_{20} = Yield on U.S. Treasury obligation, 20 year constant maturity.
†Monthly required return (k) calculated as value weighted average. Quarterly values are simple averages of monthly figures.
‡Risk premium calculated as $k - i_{20}$.

The results appear quite plausible. The estimated risk premia are positive, consistent with equity owners demanding a risk premium over and above returns available on debt securities. Also, as would be expected for less risky stocks, the utility risk premia consistently fall below those estimated for stocks in general. Exhibit 2 shows that estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Such changes will be examined in a subsequent section.

For comparative purposes, Exhibit 3 provides results of related studies. The long-run differential return between stocks and long-term government bonds (Panel A) has been about 6.4% per year (on a geometric basis). It is comforting to note that this is very close to the 6.16% average annual risk premia estimated in Exhibit 2. Note, however, that such risk premia appear to change over time. Panels B and C show some of Brigham *et al.*'s risk premium estimates. Unfortunate-

[8]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke, and Zumwalt [11]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grew at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data (with a quarterly growth rate) and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends, on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in that risk class).

In this work, D_1 is calculated as $D_0(1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "½ g" adjustment would allow for growth, the remaining "½ g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecasts of such a detailed nature exist, such a procedure is not possible. To get a feel for the magnitudes involved, the average dividend yield (D_1/P_0) and growth (market value weighted 1982–1984) for the SP500 were 5.8% and 12.5%. Comparable figures for the SP utility index were 10.4% and 6.7%. As a result, a "full g" adjustment on average increases the required return by 60–70 basis points (relative to no g adjustment) for both indices.

[9]Brigham, Shome, and Vinson [2] also use this interest rate to create equity risk premia. The results were robust to changes in weighting. For the SP500, equal weighting (rather than value weighting) increased the 1982–1984 risk premium by two basis points while for the SPUT equal weighting resulted in a 21 basis point increase. As a further test, the SP500 stocks were ranked on g and the upper and lower deciles deleted. The resulting risk premium (1982–84 average) was 5.94%. A similar procedure used to rank dividend yield produced an SP500 risk premium of 6.18%.

Exhibit 3. Results of Related Studies: Historical Returns and Estimated Risk Premia

	Geometric	Arithmetic
A. Historical Return Realizations (1926–1980)*		
Common Stocks	9.4%	11.7%
Long-Term Government Bonds	3.0%	3.1%
U.S. Treasury Bills	2.8%	2.8%

	Dow Jones Industrials		Dow Jones Electrics	
	Average	Range	Average	Range
B. DCF risk premia using one analyst†				
1966–1970	5.45	4.97–6.81	3.91	3.46–4.13
1971–1975	5.51	4.95–6.92	5.95	4.52–8.72
1976–1980	6.23	5.09–6.88	5.82	5.55–6.21
1981	5.38		5.62	
1982	5.30		3.70	
1983	5.87		5.64	
1984	3.75		4.06	
Average 1982–1984	4.97		4.47	

	Electric Utilities
C. DCF risk premia using three analysts‡	
1981	3.73
1982	4.52
1983	5.17
1984 (through June)	5.01

*Ibbotson, Sinquefield, and Siegel [9].
†Analyst is Value Line. Data are annual estimates using two-stage growth DCF model. Source: Brigham, Shome, and Vinson [2].
‡Analysts are Value Line, Merrill Lynch and Salomon Brothers. Data are averages of monthly values from Brigham, Shome, and Vinson [2].

Exhibit 4. Risk Premia by Moody's Bond Ratings*

Electric Utilities: SIC's 4911 and 4931	Aaa	Aa	A	Baa
Risk Premia				
Risk Premium (Expectational g)	3.60	4.33	4.81	4.90
Risk Premium (Historical g†)	6.10	3.28	3.09	5.24
Financial Data				
Debt Ratio‡	0.46	0.48	0.50	0.51
Beta§	0.58	0.61	0.62	0.61
Variability¶				
Operating Cash Flow	0.009	0.016	0.022	0.059
Equity Cash Flow	0.006	0.013	0.019	0.024
Standard Deviation** of Analysts' Forecasts	1.00	1.26	1.33	1.79

*Moody's ratings as of January 1984 from *Moody's Bond Record*, February 1984. The number of companies by rating is Aaa (2), Aa (22), A (32), Baa (22). Risk premia are averages of monthly values, January 1982–September 1983.
†Historical Growth is past five-year earnings growth, based on 20 quarters of past data. Source: IBES.
‡Debt Ratio = Long-Term Debt ÷ Total Capital, average 1978–1982 from COMPUSTAT.
§Beta from *Value Line*, January 29, 1982.
¶Measure of variability around trend growth: variance of residuals of regressions on quarterly COMPUSTAT data (1978–1982). Regressions are log of variable regressed on time and seasonal dummies.
**This is the average value of the standard deviation around the mean long-term growth forecast. Such standard deviations are reported for each company in each month. Note it is *not* the cross-sectional standard deviation of growth rates among companies.

ly, their work does not include a broad market index directly comparable to the SP500. Rather, they use the Dow Jones Industrial Index based on 30 large industrial concerns. Though the SPUT includes a broader set of utilities than the electrics covered by Brigham *et al.*, their average risk premium estimates are also in the 4 to 5% range for the early 1980s.

While the estimates in Exhibit 2 are quite plausible, the question still remains as to whether they satisfy economic criteria one would expect of risk premia. In the following section, the estimated risk premia are subjected to a series of tests to see if they vary both cross-sectionally and over time with changes in risk. The tests are ultimately joint tests of the estimates as useful risk premia, the measured proxies for risk and the validity of the economic hypothesis. Nonetheless, if the tests using the risk premia have results conforming to theoretical expectation, the comfort level in using them is increased accordingly.

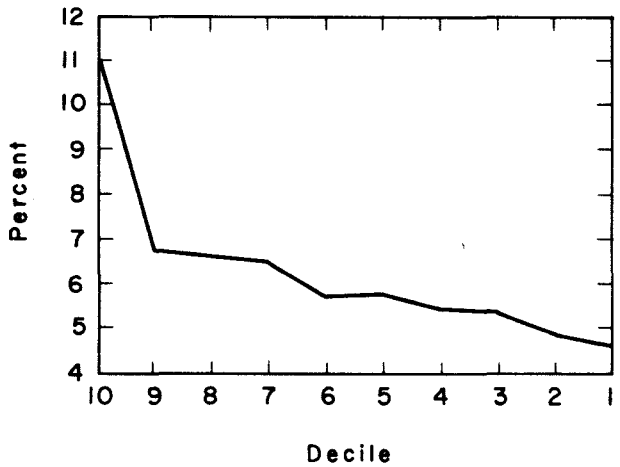
V. Characteristics of Risk Premia

A. Cross-Sectional Tests

Brigham *et al.* show that risk premia (IBES estimates for first half of 1984) for electric utilities are lower the higher the bond rating of the company, confirming the expected tradeoff between risk and return. A similar experiment for electrics, using the current data stretching back to January 1982, confirmed this relationship for a longer time period. Exhibit 4 reports selected results of that analysis. As a contrast, Exhibit 4 also shows the results of using historical growth rates (rather than FAF) in a DCF model. Risk premia derived from historical growth are actually higher for companies with very safe debt, suggesting the clear inferiority of historical to expectational growth rates. With the exception of beta, which is roughly constant across groups, other measures of risk noted in Exhibit 4 confirm the risk differentials associated with bond rating groups.

A further test of the cross-sectional variation in risk premia was performed by dividing the universe of

Exhibit 5. Equity Risk Premia: Deciles Based on Standard Deviation of Financial Analysts Forecasts* (Companies with at least three analysts)



*Risk premia were calculated as equally weighted averages for each decile (10 = highest dispersion) for each of three months: January 1982, December 1982, and September 1983 (approximately 50 companies per decile). These premia were then averaged across deciles. A similar downward pattern was evident in each month.

stocks (industrial plus utility) according to the dispersion of analysts' forecasts, σ_g. This cross-sectional measure of analysts' disagreement should be positively related to the uncertainty of future growth prospects and hence to the riskiness of equity investment. Elsewhere, Malkiel [12] has discussed the rationale and usefulness of such dispersion as an *ex ante* measure of risk. Malkiel argues that σ_g may be a proxy for systematic risk and shows that it bears a closer empirical relationship to expected return than does beta or other risk measures. Most of Malkiel's work is, however, based on data from the 1960s. Exhibit 5 reports risk premia by decile based on σ_g for companies having at least three analysts' forecasts. The three months were chosen as representative. The results show a consistent positive relationship between risk premia and dispersion of analysts' forecasts.

The results in Exhibits 4 and 5 show that the estimated risk premia conform to theoretical relationships between risk and required return that are expected when investors are risk averse. This strengthens the case for using such risk premia, and provides encouragement for further study of their structure.[10]

[10]Such *ex ante* required returns offer a useful alternative to *ex post* data typically used in tests of asset pricing models. See Friend, Westerfield, and Granito [7] for a test of the CAPM using survey data rather than *ex post* holding period returns.

B. Time Series Tests

A potential benefit of using *ex ante* risk premia is the estimation of changes in risk premia over time. Brigham *et al.* [2] note such changes for utility stocks and relate them to changes in interest rates. They conclude that prior to 1980 utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. They explain this turnaround as the outcome of changes in bond markets and adaptation of utilities and their regulators to an inflationary environment. Brigham *et al.* do not, however, analyze changing risk premia for stocks in general. Furthermore, they do not provide direct empirical proxies for changes in equity risks that would explain changes in equity risk premia over time.[11]

C. Changes in Risk Premia

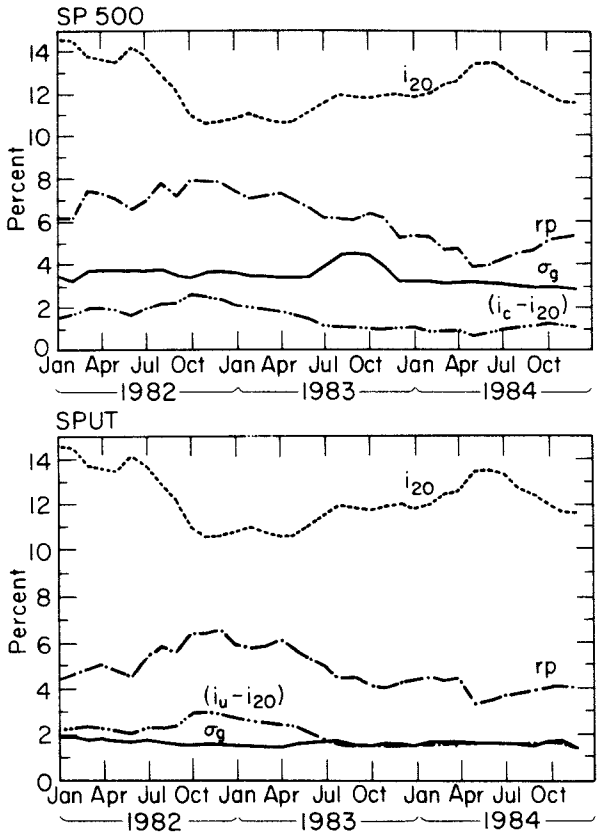
One would expect changes in measured equity risk premia to be related to changes in perceived riskiness. First, with changes in the economy and financial markets, equity investments may be perceived to change in risk. Second, since government bonds are risky investments themselves, their perceived riskiness may change. For example, the large increase in interest rate volatility in the last decade has undoubtedly made fixed income investments more risky holdings than they were in a world of relatively stable rates. Measured equity risk premia (relative to government bonds) could thus be reduced due to increases in perceived riskiness of bonds, even if equities displayed no shifts in risk.

One measure of risk, the standard deviation of FAF, σ_g, was shown previously to be related to cross-sectional differences in risk premia. To test its usefulness as a time series measure of risk, the average value of σ_g was calculated each month for the SP500 index and the SPUT index. The results are graphed in Exhibit 6.[12]

[11]In addition, Brigham *et al.* do not report on their treatment of serial correlation in reported regression results, making it more difficult to interpret their findings. As an example, monthly data are used for the 1980–1984 period in a time series regression of a risk premium on the level of interest rates. Similar regressions using data in this paper (1982–1984 monthly data) showed significant positive autocorrelation with Durbin Watson Statistics well below 1.0.

[12]The average values of σ_g are the market value weighted averages of the σ_g for individual stocks. If one looked at a direct estimate of g made by individual analysts for the index, one would expect to find a lower amount of dispersion because some of the differences on individual securities would cancel out. Such data are not available. One would suspect, however, that the calculated average would move up and down in tandem with this unobservable measure of dispersion.

Exhibit 6. Equity Risk Premia, Interest Rates and Risk



Another possible time series proxy for equity risk is the set of yield spreads between corporate and government bonds. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders.[13] Exhibit 6 graphs two series of yield spreads. The first is the difference between the yield on Moody's corporate average series and the yield on 20-year U.S. Treasury obligations. This series includes debt of both industrial and utility companies and thus would be appropriate as a risk proxy for a broad market index such as the SP500. The second is the spread between the yields on Moody's public utility series and 20-year U.S. Treasury bonds. This series should reflect relative risks of utility stocks as proxied by SPUT.[14]

Exhibit 7 reports results of analyzing the relationship between risk premia, interest rates, and proxies for risk for both the SP500 and SPUT. All regressions are corrected for serial correlation.[15] For stocks in general, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by i_{20}. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

The results also show the significant positive relationship between the two proxies for risk and the estimated risk premia. For example, regression 4 of Panel A shows that the equity premium on the SP500 increases with the dispersion of FAF (σ_g) and the yield spread between corporate and government bonds ($i_c - i_{20}$). Evidently, these two risk measures capture somewhat different dimensions of risk, both of which appear important in explaining risk premia on stocks in general. The simple correlation coefficient between the two risk measures is 0.19 and is insignificantly different from zero. The addition of the yield spread risk proxy also dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 3 of Panel A. Apparently, a large part of the effect of changes in government bond rates on equity risk premia may be explained through the narrowing of the yield spread between corporate and government bonds. This suggests that such increases in government yields may often be associated with a reduction in the *difference* in risk between investment in government bonds and in corporate activity.

Panel B shows that utility risk premia are also inversely related to the level of interest rates as was found by Brigham *et al.* [2]. Unlike the results for stocks in general, however, changes in the dispersion of FAF over time are not significantly related to changes in these utility risk premia. This may be be-

[13]Of course, counterexamples could be constructed but one would expect an overall positive correlation across companies. Additionally, the cross-sectional relationship between bond ratings and equity risk premia reported earlier in the paper supports the link between corporate debt risks and risks on equity.

[14]Note that these two series reflect both changes in the ratings of corporate bonds as well as yield spreads for a given bond rating. The two series proved better in explaining equity risk premia than use of two comparable series for AA-rated debt.

[15]Ordinary least squares regressions showed severe positive autocorrelation in many cases with Durbin Watson Statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [10], pp. 321–325.

Exhibit 7. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value)

Regression	Intercept	i_{20}	σ_g	$i_c - i_{20}$	R^2
A. SP500: Dependent Variable is Equity Risk Premium*					
1.	0.140	−0.632			0.43
	(8.15)†	(−4.95)†			
2.	0.118	−0.660	0.754		0.58
	(7.10)†	(−5.93)†	(3.32)†		
3.	0.069	−0.235		1.448	0.57
	(3.44)†	(−1.76)		(4.18)†	
4.	0.030	−0.177	0.855	1.645	0.79
	(2.17)†	(−2.07)†	(4.68)†	(7.63)†	
Regression	Intercept	i_{20}	σ_g	$i_u - i_{20}$	R^2
B. SPUT: Dependent Variable is Equity Risk Premium*					
1.	0.110	−0.510			0.37
	(7.35)†	(−4.41)†			
2.	0.101	−0.543	0.805		0.41
	(6.28)†	(−4.68)†	(1.42)		
3.	0.051	−0.259		1.432	0.80
	(5.54)†	(−4.05)†		(8.87)†	
4.	0.049	−0.287	0.387	1.391	0.80
	(5.15)†	(−3.87)†	(0.75)	(8.14)†	

*All variables are defined in Exhibit 1 and graphed in Exhibit 6. Regressions were estimated for the 36 month period January 1982–December 1984 and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression variables are expressed in decimal form, *e.g.*, 14% = 0.14.

†Significantly different from zero at 0.05 level using two-tailed test.

cause of lower variability over time in the dispersion of FAF for utility stocks as compared to equities in general. The yield spread between utility and government bonds is significantly positively related to utility equity risk premia. And, as in the case of stocks in general, introduction of this spread substantially reduces the independent effect of interest rate levels on equity risk premia.

Given the short time series (36 months), tests for the stability of the relationships found in Exhibit 7 present difficulties. As a check, the relationships were reestimated dividing the data into two 18-month periods. For stocks in general (SP500), coefficients on σ_g and $(i_c - i_{20})$ were positive in all regressions and significantly so, except in the case of $(i_c - i_{20})$ for the second 18-month period. The coefficient of i_{20} was significantly negative in both periods. This confirms the general findings for the SP500 in Panel A of Exhibit 7. For utility stocks, results for the subperiods also matched the entire period results. The coefficients of $(i_u - i_{20})$ were significantly positive in both subperiods while those of σ_g were insignificantly different from zero. The level of interest rates (i_{20}) had a significant negative effect in both subperiods.

In summary, the estimated risk premia change over time and the patterns of such change are directly related to changes in proxies for the risks of equity investments. Risk premia for both stocks in general and utilities are inversely related to the level of government interest rates but positively related to the bond yield spreads which proxy for the incremental risk of investing in equities rather than government bonds. For stocks in general, risk premia also increase over time with increases in the general level of disagreement about future corporate performance.

VI. Conclusions

Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations. When such forecasts are used to derive equity risk premia, the results are quite encouraging. In addition to meeting the theoretical requirement of using expectational data, the procedure produces estimates of reasonable magnitude that behave as econom-

ic theory would predict. Both over time and across stocks, the risk premia vary directly with the perceived riskiness of equity investment.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (*e.g.*, portfolios of utility stocks) appropriate for a particular decision. An additional advantage of the estimated risk premia is that they allow analysis of changes in equity return requirements over time. Tracking such changes is important for managers facing changing economic climates.

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THE ECONOMICS OF REGULATION

Theory and Practice in the Transportation and Public Utility Industries

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for flotation and underpricing costs involved in the issuance of additional stock. An allowance of 10 percent is common and would result in an adjusted ratio of 8.3 percent—7.5 percent divided by 0.90.) This ratio implies that if the earnings-price ratio of a company has been running fairly consistently at 7.5 percent, then the stock will continue to sell at approximately its book value if future earnings per share amount to 8.3 percent of this book value.

Dividend-Price Ratio. If a stock has an average market value of $150 and the annual dividend is $9.00, the dividend-price ratio is 6 percent. This ratio thus represents the yield received by the investor at the average market price. Whereas the earnings-price ratio implies that investors are guided on the basis of earnings, the dividend-price ratio implies that investors are guided by dividend yields.[81]

For many years, it was thought that investors bought utility stocks largely on the basis of dividends.[82] More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[83] Both ratios must be used with a great deal of caution because they may fail to indicate an adequate rate of return to attract capital. As stated by the California commission in a 1954 decision:

> Earnings-price ratios and dividend-price ratios merely reflect the prospective investors' appraisal of the market value of stock and as such are influenced by prevailing market and economic conditions and the individual requirements of the purchaser. While useful for comparative purposes and of value in presenting background information, they are not conclusive in themselves in the determination of the allowable fair return on investment in operative properties. It is one thing to say that these ratios indicate the terms under which a new investor might devote his money to the business; it is another thing to say that these terms represent or limit the return the applicant is entitled to receive on the capital committed to the service. It seems to us that reliance on ratios of this nature results in a restricted view of the subject of rate-of-return. Obviously, the price at which a security is bought on the market reflects anticipated earnings rather than past results of operations and it by no means follows that the rates at which present market sales prices are related to the past earnings represents the returns the purchasers at those prices are willing to accept in the future.

[81] Both earnings-price and dividend-price ratios "should cover representative periods of operation. Ratios used on a 'spot' basis, for a period of a month, or even a year, might produce very unsatisfactory results. Prices of utility stocks of the most stable type are influenced by short-run considerations—threats of war, tax legislation, changing governmental regulations, strikes, elections—all affect stock prices in one way or another. For dividend yields or earnings-price ratios to be really significant they must be considered over a sufficiently long period of time for the abnormal and unusual pressures to average out." Lionel W. Thatcher, "Cost-of-Capital Techniques Employed in Determining the Rate of Return for Public Utilities," 30 *Land Economics* 85, 92 (1954).

[82] See Eli W. Clemens, "Some Aspects of the Rate-of-Return Problem," 30 *Land Economics* 32, 34-35 (1954).

[83] See Fred P. Morrissey, "Current Aspects of the Cost of Capital to Utilities," 62 *Public Utilities Fortnightly* 217 (1958).

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* * *

EVALUATING COMMON STOCKS USING VALUE LINE'S PROJECTED CASH FLOWS AND IMPLIED GROWTH RATE

A well-known principle in finance is that the value of a firm must reflect its long-run growth opportunities. In an extensive study, Rappaport [1986] finds that over 60% of the firm's market value is attributable to earnings occurring beyond the immediate five-year horizon. When a firm does not meet analysts' expectations for a given quarter, its long-run potential is often discredited by the investment community. The basic reason for this overreaction is primarily that capital is scarce and, at least for the time being, the opportunity cost is higher somewhere else.

In practice, financial analysts evaluate a firm's growth opportunities by equating its P/E ratio to the growth rate of its earnings.(n1) Thus, the price of the firm's stock follows the volatility of its earnings.

If a firm's earnings are temporarily lower, whether due to seasonality in its business or some other transitory event, but the firm's long-run potential is not impaired, its stock may be called underpriced. This phenomenon is particularly common among semiconductor and other capital equipment companies, which demonstrate fairly frequent boom and bust cycles. In such cases, it is difficult to determine the true growth rate of the firm's earnings, or cash flows, by looking at its historical data.

A preferred way to estimate the firm's long-run growth rate is to deduce it from publicly available data that incorporate expectations concerning the firm's future cash flows. The most widely known source of such data is "Value Line's Investment Survey." Some empirical studies have shown that stock prices react swiftly to Value Line's recommendations.(n2)

The purpose of this article is to demonstrate how investors can use the information from Value Line to assess the long-term, or expected, value of a firm's equity. We follow a simple methodology that is well known in finance and is found in many, basic textbooks. Briefly, we apply the discounted cash flow (DCF) approach to the data supplied by Value Line and compute the price of the firm's common stock, using some reasonable assumptions.

In addition, the study solves for the long-term growth rate implied by the firm's equity cash flows. This rate may be contrasted to various subjective expected rates, or the growth rate for the entire industry, in the form of a sensitivity analysis. If the current price of the stock does not reflect the true long-run rate implied by the firm's cash flows, the stock may be underpriced. Conversely, if the implied rate is greater than the expected growth rate, the stock may be overpriced.

The strategy has several advantages over other security analysis and portfolio selection strategies. It considers forward-looking cash flows, rather than historical information, and

concentrates on the firm's long-term rather than short-term performance.

The methodology is applied to the pricing of MCI's common stock as an example. The results of this simple application are intriguing and promising for investors and analysts, as well as academicians and students of corporate finance.

DISCOUNTED CASH FLOW APPROACH

The discounted cash flow approach (DCF) is the most familiar theoretical method of estimating the firm's value. According to this approach, the value of a firm is the present value of the firm's stream of future expected cash flows discounted at a rate that reflects the riskiness of these cash flows. This approach is widely used by security analysts and financial managers and is consistent with the maximization of shareholder wealth, which is the goal of the management of every corporation. In exploratory research, Copeland, Koller, and Murrin [1996] find a correlation between the market value (actual price per share) and the DCF-based value, using forecasts from the Value, of 0.97.

Although in practice there may be a variety of approaches to valuation of the firm's prospects, the discounted cash flow technique is the most commonly used practical approach to determining a company's value. It is used in capital budgeting decisions to evaluate investment projects or to price entire corporate entities that may be targets for acquisition.

The DCF is expressed as:

(1) [Multiple line equation(s) cannot be represented in ASCII text]

where PV is the present value, n is the number of periods, CF_t are the cash flows that occur in time period t, and r is the relevant discount rate.

If these cash flows were to grow at an annual rate of g%, beginning at year 6, expression (1) becomes:

(2) [Multiple line equation(s) cannot be represented in ASCII text]

The discount factor $1/(1 + r)^5$ is used to discount the collective value of the cash flows at year 6 back to year zero, the present time. The term [(1 + g)/(r - g)] is called the terminal value multiple. It expresses the ratio of the value of the cash flows beyond year 6 to the value of the cash flow of year 5. The price of the firm's stock, P, can then be found by dividing the value of its equity by the number of shares outstanding, N, or P = (PV/N). Of course, if PV represents the present value of the firm's equity and debt, then the value of the firm's debt is first subtracted, and the remaining value is divided by the number of common shares outstanding to obtain the price per

share.

Assuming reliable estimates of the cash flows of the first five years and the discount rate, r, Equation (2) can be applied in conjunction with the firm's value of equity to solve for the implied average growth rate, g, in its distant equity cash flows. This implied growth rate can then be contrasted with various subjective expected rates in the form of a sensitivity analysis. A reasonable choice for the expected growth rate of a firm's equity cash flows would be the one implied by its industry peers, adjusted for opportunities unique to the firm.

In any event, if the implied growth rate is lower than what an investor would have expected, the stock may be underpriced. Conversely, if the implied rate is greater than the expected growth rate, the stock may be overpriced.

CASH FLOWS TO EQUITYHOLDERS

Shareholders' cash flows can be summarized by:

(3) CF_E = EBIT(1- t) - I(1- t) + NCE - Delta WC - CE

where CF_E is cash flow to equity; EBIT is earnings before interest and taxes; T is the corporate tax rate; NCE is non-cash expenses; Delta WC is changes in working capital; and CE is capital expenditures. The cash flows to the debtholders, I_{AT} = I(1- T), imply a tax shield to the common stockholders equal to the firm's marginal tax rate times the interest expense, since I(1- T)= I- IT. This tax shield reduces the firm's cost of debt capital that is used to discount the cash flows to debt in Equation (3). Thus, by discounting the firm's after-tax interest expense by the corresponding after-tax cost of debt, we obtain the value of the firm's debt.

Some authors, including Copeland, Koller, and Murrin [1996], find the present value of the free cash flows to both debt and equity using a weighted average cost of capital and subtract the firm's debt to obtain the market value of its equity. Since the book value of the firm's debt may not be equal to its market value, the preferred approach is to consider only the firm's cash flows to equityholders and discount them by the corresponding cost of equity capital.

Equation (3) can be further simplified as:

(4) CF_E = NI + NCE - Delta WC - CE

where:

(5) NI = EBIT(1- T) - I(1- T)

In order to completely define the variables used in Equation (3), a definition of earnings before interest and taxes is necessary. In general, earnings before interest and taxes is defined as total revenues minus costs and depreciation, or

(6) EBIT = (S + NOI) - (COGS + SGA + R&D) - (Depr)

where S are revenues from the firm's sales; NOI is non-operating income; COGS is cost of goods sold; SGA is selling, general, and administrative expenses; R&D is research and development expenses; and Depr is depreciation. Finally, by substituting Equation (6) into (5) and subsequently into (4) and adjusting for dividend payments to preferred shareholders, denoted by D_p, we obtain Equation (7):

(7) CF_C = (S + NOI - COGS - SGA - R & D - Depr) x (1- T) - I(1-T) + NCE - Delta WC - CE - D_P

where the subscript C denotes cash flows to common equityholders.

VALUE LINE CASH FLOWS

Because of its consistency and broad coverage of stocks, "Value Line Investment Survey" serves as a unique source of information and is widely used by both academicians and practitioners.(n3) This service follows 1,700 companies in over ninety-five industries that represent 94% of the trading volume on all U.S. stock exchanges. It provides subscribers with a detailed one-page overview of each company's past, current, and expected performance for the next four to five years.

In fact, Value Line is the only investment service that provides detailed information for a company's expected short-term performance. Each page offers financial data, trend line growth rates, graphical price history patterns, quarterly sales figures, earnings and dividends, some key financial ratios, and balance sheet information. Value Line also rates companies for timeliness and safety. Furthermore, investors learn, through a summarized text, about the general business and analyst expectations for each company. All data are updated every thirteen weeks on a weekly sequence.

Using the Value Line definition of variables, Equation (7) becomes:

(8) $CF_{C,\,t}$ =(S_t m_t - $Depr_t$- I)(1- T_t) + $Depr_t$ - Delta WC_t - CE_t - $D_{p,\,t}$

where m_t is the operating margin as a percent of sales at year t. Equation 8 constitutes the basis for estimating the cash flows to common equity. Note that if a firm decides to either obtain additional debt or repay part or all of its existing debt, Equation (8) must be modified to reflect

this change in leverage.

Exhibit 1 shows the variables in Equation (7) and the corresponding entries from Value Line expressed in (8).

Value Line's projections refer to the range of the three-year period following the year subsequent to the date of the survey. For example, if the survey's date is October 1997, the projections refer to the period 2000-2002, hence covering a five-year window. We assign the projections for the three-year range to the middle year, which is labeled as year 4. The figures for the years 2 and 3 are geometrically interpolated, while the figures for year 5 are extrapolated using the implied growth rate of the previous four years. For an October 1997 survey date, 1998 is the first year, and 2001, the midpoint of the range 2000-2002, represents the fourth year. The data for the fifth year, 2002, are extrapolated on the basis of the growth rate implied between the years 1998 and 2001. Following this practice, we are able to calculate successive cash flows for the ensuing five years.

Following Equation (2), we then assume that the cash flows for years 6 and beyond will grow at an average constant rate g. If we further assume that the firm's cost of equity capital is given by r, we can then solve for either the PV_0, if we know g, or vice versa.

THE COST OF EQUITY CAPITAL

The rate used to discount the firm's cash flows to its equityholders, also termed the cost of capital, is obtained from the capital asset pricing model (CAPM). According to this model, the expected rate of return for a common stock required by investors, $E(R_{C,i})$, equals the sum of two components: namely, the riskless rate of return, R_f, and a risk premium, $Beta_i[E(R_M) - R_f]$. This relationship is expressed by the equation:

(9) $E(R_{c,i}) = R_f + Beta_i [E(R_M) - R_f]$

where $Beta_i$ is the beta of company i, which reflects its operating and financial risks. Generally, companies in specific industries with cyclical demand, such as real property and electronics, are associated with higher betas. Companies in the utility industry, like telephone and energy, tend to be less sensitive to market movements, and consequently they exhibit lower betas.

The risk-free rate is approximated by the three-month U.S. Treasury bill rate, and the risk premium represents the reward for bearing risk. The term $E(R_M)$ is the expected return on the market portfolio. In theory, the market portfolio incorporates all risky assets. In practice, however, it is unobservable and it is usually represented by a well-diversified index, such as the Chicago Center for Research in Security Prices (CRSP) value-weighted index. Possible alternatives are the NYSE composite index or the Wilshire 5000 equity index.

A common practice in estimating the market risk premium [$E(R_M) - R_f$], is to assume that it approximates the difference between the historical rate of return on stocks and Treasury bills. According to Stocks, Bonds, Bills, and Inflation, the difference is 8.6% (12.3%-3.7%). Thus, even if both equities and Treasury securities drift away from their historical levels, it is assumed that their difference remains constant through time, or at least reverts to its long-term historical average. Following this approach, a stock with a beta of 1.2 would command a cost of equity capital of approximately 14%.

EXAMPLE: VALUATION OF MCI

Beginning in November 1996, MCI has been considering different consolidation proposals from three competitors in the telecommunications industry: British Telecom, GTE, and WorldCom. The offer by WorldCom prevailed over the other two offers, and the shareholders of both firms have approved the proposed merger at an exchange ratio that amounts to $51.00 per MCI share. (n4) This represents a 60% to 100% premium over the 1996 range of prices for MCI shareholders.

The rationale for such a premium may be justified by the synergistic effect of the MCI/ WorldCom merger. In principle, such a synergistic premium exists for many companies, and shareholders need a simple technique to assess it. It is hoped that our methodology will provide such a means and enable investors to take full advantage of the information supplied by Value Line.(n5)

Application of the analysis to MCI is summarized in the four worksheets in Exhibits 2-5.(n6) Exhibit 2 presents the pertinent inputs for the other exhibits. The projected figures refer to a range of two to four years. Exhibit 3 assumes that these figures correspond to the mid-range year, i.e., 2001. The figures for the years 1999 and 2000 are found by interpolation, assuming a geometric growth between the first and the fourth years, i.e., 1998 and 2001. These growth rates are subsequently used to find the 2002 figures, by extrapolating the data of the year 2001. Following this approach we are able to obtain the estimated cash flows to equityholders for the subsequent five years.

Exhibit 4 shows the estimation of the firm's cost of equity capital, using the capital asset pricing model given by Equation (9). These estimates use two variations of the proxy for the risk-free rate: a historical estimate of 3.7%, as calculated by Ibbotson Associates, and the prevailing rate of interest on three-month T-bills. Exhibit 4 provides a series of estimated costs of capital corresponding to a sequence of betas, ranging from 30% below to 30% above the Value Line beta, in increments of 10.%. The worksheet allows the user to input an estimate for the continuing growth rate of the cash flows to equityholders and the increment for higher and lower growth rates.

Finally, Exhibit 5 presents the sensitivity analysis for various expected continuing growth rates and various costs of equity, corresponding to the series of betas considered in Exhibit 4. Assuming that the middle rates represent the investor's best estimates for continuing growth rate and cost of equity, the center cell of the price matrix represents the most likely price for the firm's stock. Given the market price of the stock, the worksheet in Exhibit 5 also calculates the implied continuing growth rate for the firm's cash flows and the "terminal value multiple." For a price of $60.50, the implied continuing growth rate for MCI's cash flows to equity is 5.4%, and the terminal value multiple is 16.

The $51.00 price offered by WorldCom implies a continuing growth rate of 4%. All in all, given that the MCI/WorldCom merger will result in substantial synergistic savings, the $51.00 offer for each MCI share by WorldCom appears to be fair.

CONCLUSIONS AND RECOMMENDATIONS

We have developed a simple yet practical methodology to evaluate common stocks by applying the DCF approach to the data supplied by Value Line to estimate the implied long-term growth rate of a firm's equity cash flows. Given the value of the firm's equity, its annual cash flows, and its cost of equity capital, one may solve for the implied long-term growth rate of the firm's cash flows. This rate can then be compared to various subjective expected rates using sensitivity analysis. If the implied growth rate is lower than investors' expectations, then the stock may be underpriced. Conversely, if the implied rate is greater than the expected growth rate, the stock may be overpriced.

The strategy has several advantages over current security analysis and portfolio selection strategies. It considers forward-looking cash flows, rather than historical information, and concentrates on a firm's long-term rather than short-term performance. It may thus be useful in assessing the equilibrium level of the overall market, especially when it is used in conjunction with other procedures for pinpointing value, such as the P/E ratio. An exploratory application of our methodology to MCI reveals encouraging results.

ENDNOTES

(n1) See Lynch [1989].

(n2) See, for example, Black [1973], Holloway [1981,1983], Copeland and Mayers [1982], Stickel [1985], Huberman and Kandel [1987,1990], Peterson [1987,1995], and Peterson and Peterson [1995]. Philbrick and Ricks [1991] have shown that in determining earnings surprise, Value Line is a better source for actual earnings per share data.

(n3) Lynch [1989] refers to "Value Line Investment Survey" as "the next best thing to having your own private securities analyst" (p. 165).

(n4) The exchange ratio is equal to the quotient of $51.00 divided by the average of the high and low market prices of WorldCom common stock on each of the twenty consecutive trading days ending with the third trading day immediately preceding the effective time of the MCI/ WorldCom merger.

(n5) According to the prospectus, the consultants and the management of the two companies believe that "the MCI/WorldCom merger will create a fully integrated communications company that will be well positioned to take advantage of growth opportunities in global communications."

(n6) The Excel workbook for this application is available from the first author upon request.

EXHIBIT 1 The Value Line Variables

Legend for Chart:

A - Parameter in Equation(7) Description
B - Represented by
C - Parameter in Value Line Description
D - Represented by

A C	B D
Sales + Non-Operating Income - Sales	S + NOI - S_t
Cost of Goods Sold - --	COGS -
Selling, General, and Admin. Expenses -	SGA -
Research & Development Expenses - Operating Expenses	R&D -
Operating Income	(S + NOI) - (COGS+ SGA+ R & D)
Value Line expresses operating income as a percent of sales, called operating	m_t (as a %

margin	of Sales)
Depreciation	Depr
Depreciation	$Depr_t$
Corporate Tax Rate	T
Income Tax Rate	T_t
Interest	I
Long-Term Interest	I_t
Working Capial	WC
Working Capital	WC_t
Capital Expenditures	CE
Capital Spending per Share x Number of Shares Outstanding	Ce_t
Annual Preferred Dividends	D_p
Preferred Dividend x Number of Shares of Preferred Stock Outstanding	$D_{p,\ t}$

EXHIBIT 2 Value Line MCI Data Input

Recent Stock Price:	$60.50
P/E Ratio:	NMF
Dividend Yield:	0.1%
Beta of the Company:	0.95
First Projected Year:	1998
Projection for Total Annual Return	7%
Projection for Total Annual Return	-5%
Company's LT Interests (millions):	$230.00

Preferred Dividends (millions): $60.00

Legend for Chart:

B-Year 1997
C-Year 1998
D-Projected for Years 2000-2002

A	B	C	D
		E	F
Capital Spending per Share			$3.50
			$2.70
Common Shares Outstanding (millions)			710.00
			740.00
Sales (millions)			$20,945
			$28,885
Operating Margin(%)			18.0%
			26.5%
Depreciation (millions)			$2,300
			$2,850
Income Tax Rate(%)			37.0%
			38.0%
Long-Term Debt		$3,300	$3,760
			$6,200
Working Capital (millions	($2,600)		
		($2,000)	($500)

EXHIBIT 3 Near-Future MCI Free Cash Flows to Equity (1,000s)

Legend for Chart:

B - 1998
C - 1999
D - 2000

E - 2001
F - 2002

A	B	C E	D F
Sales	$20,945,000	$22,476,894 $25,885,000	$24,120,829 $27,778,200
--Operating Costs	$17,174,900	$17,874,329 $19,025,475	$18,501,985 $19,404,043
Operating Margin	$3,770,100	$4,602,564 $6,859,525	$5,618,844 $8,374,157
--Depreciation	$2,300,000	$2,470,397 $2,850,000	$2,653,419 $3,061,144
EBIT	$1,470,100	$2,132,167 $4,009,525	$2,965,425 $5,313,012
--Long-Term Interest	$230,000	$230,000 $230,000	$230,000 $230,000
Earnings Before Taxes	$1,240,100	$1,902,167 $3,779,525	$2,735,425 $5,083,012
--Income Taxes	$458,837	$722,823 $1,436,219	$1,039,461 $1,931,544
Net Income	$781,263	$1,179,343 $2,343 305	$1,695,963 $3,151,467
+ Depreciation	$2,300,000	$2,470,397 $2,850 000	$2,653,419 $3,061,144
--Change in WC	$600,000	$500,000 $500 000	$500,000 $500,000
Operating Cash Flow	$2,481,263	$3,149,741 $4,693 305	$3,849,382 $5,712,612
--Capital Expenditures	$2,485,000	$2,310,731	$2,148,683

		$1,998 000	$1,857,883
--Preferred Dividends	60,000	60,000	60,000
		$60 000	60,000
--Change in LT Debt	$460,000	$813,333	$813,333
		$813 333	0
CF (Equity)	$396,263	$1,592,343	$2,454,032
		$3,448,638	$3,794,728

EXHIBIT 4 Estimating the MCI Cost of Equity

Beta	0.95
Beta Interval:	10%
Historical Risk-free Rate (H):	3.7%
Current Risk-free Rate (C):	5.0%
Expected Return on the Market:	12.3%
Market Risk Premium:	8.6%

To use historical risk-free rate, input 1; otherwise input 2:

Legend for Chart:

A - Beta:
B - 0.67
C - 0.76
D - 0.86
E - 0.95
F - 1.05
G - 1.14
H - 1.24

A	B	C	D	E
	F	G	H	
Cost of Equity (H):	9.4%	10.2%	11.1%	11.9%
	12.7%	13.5%	14.3%	
Cost of Equity (C):	10.7%	11.5%	12.4%	13.2%
	14.0%	14.8%	15.6%	

Expected continuing growth rate

for cash flows to equity: 5.0%

Interval length for growth rates: 1.0%

EXHIBIT 5 MCI Sensitivity Analysis

Legend for Chart:

B - BETA:
C - 0.67
D - 0.76
E - 0.86
F - 0.95
G - 1.05
H - 1.14
I - 1.24

A	B	C F	D G	E H I
	Cost of Equity:	9.40% 11.90%	10.20% 12.70%	11.10% 13.50% 14.30%
	0.00%	$48.00 $36.61	$43.58 $33.81	$39.83 $31.37 $29.21
	1.00%	$52.70 $39.25	$47.41 $36.05	$42.99 $33.28 $30.85
	2.00%	$58.67 $42.44	$52.17 $38.70	$46.85 $35.51 $32.76
	3.00%	$66.50 $46.33	$58.24 $41.91	$51.67 $38.18 $35.00

Expected	4.00%	$77.22	$66.26	$57.86
		$51.22	$45.84	$41.40
				$37.68
continuing	5.00%	$92.79	$77.35	$66.09
		$57.53	$50.81	$45.39
				$40.93
growth rate	6.00%	$117.47	$93.66	$77.58
		$65.99	$57.26	$50.44
				$44.97
	7.00%	$162.55	$120.07	$94.74
		$77.93	$65.97	$57.03
				$50.10
	8.00%	$271.18	$170.09	$123.14
		$96.04	$78.41	$66.03
				$56.86
	9.00%	N/A	$301.05	$179.20
		$126.76	$97.59	$79.02
				$66.17
	10.00%	N/A	N/A	$341.75
		$190.35	$131.04	$99.42
				$79.78
Implied growth rate:	5.40%			Recent Price:
		$60.50		TVM: 16

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Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts

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■ One of the most widely used concepts in finance is that shareholders require a risk premium over bond yields to bear the additional risks of equity investments. While models such as the two-parameter capital asset pricing model (CAPM) or arbitrage pricing theory offer explicit methods for varying risk premia across securities, the models are invariably linked to some underlying market (or factor-specific) risk premium. Unfortunately, the theoretical models provide limited practical advice on establishing empirical estimates of such a benchmark market risk premium. As a result, the typical advice to practitioners is to estimate the market risk premium based on historical realizations of share and bond returns (see Brealey and Myers [3]).

In this paper, we present estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts. We update, through 1991, earlier work which, due to data availability, was restricted to the period 1982-1984 (Harris [12]). Using stronger tests, we also reexamine the efficacy of using such an expectational approach as an alternative to the use of historical averages. Using the S&P 500 as a proxy for the market portfolio, we find an average market risk premium (1982-1991) of 6.47% above yields on long-term U.S. government bonds and 5.13% above yields on corporate bonds. We also find that required returns for individual stocks vary directly with their risk (as proxied by beta) and that the market risk premium varies over time. In particular, the equity market premium over government bond yields is higher in low interest rate environments and when there is a larger spread between corporate and government bond yields. These findings show that, in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.

Section I provides background on the estimation of equity required returns and a brief discussion of related

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literature on financial analysts' forecasts (FAF). In Section II, models and data are discussed. Following a comparison of the results to historical risk premia, the estimates are subjected to economic tests of both their time-series and cross-sectional characteristics in Section III. Finally, conclusions are offered in Section IV.

I. Background and Literature Review

In establishing economic criteria for resource allocation, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds or other equities) and the riskiness of the stock. To isolate the effects of risk, it is useful to work in terms of a risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.[1]

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a benchmark "market" risk premium which then may be adjusted for the relative risk of individual stocks (e.g., using the CAPM or a variant). The historical studies of Ibbotson Associates [13] have been used frequently to implement this approach.[2] This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that risk premia are constant over time. Carleton and Lakonishok [5] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

As an alternative to historical estimates, the current paper derives estimates of k, and hence, implied values of rp, using publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow or DCF model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier works by Malkiel [17], Brigham, Vinson, and Shome [4], and Harris [12] have used FAF in DCF models, and this approach has been employed in regulatory settings (see Harris [12]) and suggested by consultants as an alternative to use of historical data (e.g., Ibbotson Associates [13, pp. 127, 128]). Unfortunately, the published studies use data extending to 1984 at the latest. Our paper draws on this earlier work but extends it through 1991.[3] Our work is closest to that done by Harris [12], who reviews literature showing a strong link between equity prices and FAF and supporting the use of FAF as a proxy for investor expectations. Using data from 1982 to 1984, Harris' results suggest that this expectational approach to estimating equity risk premia is an encouraging alternative to the use of historical averages. He also demonstrates that such risk premia vary both cross-sectionally with the riskiness of individual stocks and over time with financial market conditions.

II. Models and Data

A. Model for Estimation

The simplest and most commonly used version of the DCF model to estimate shareholders' required rate of return, k, is shown in Equation (2):

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[4] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future perfor-

[1]Theoretically, i is a risk-free rate, though empirically its proxy (e.g., yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk. In this development, the effects of tax codes on required returns are ignored.

[2]Many leading texts in financial management use such historical risk premia to estimate a market return. See, for example, Brealey and Myers [3]. Often a market risk premium is adjusted for the observed relative risk of a stock.

[3]See Harris [12] for a discussion of the earlier work and a detailed discussion of the approach employed here.

[4]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at a rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon. One could alternatively estimate a nonconstant growth model, although the proxies for multistage growth rates are even more difficult to obtain than single stage growth estimates. Marston, Harris, and Crawford [19] examine publicly available data from 1982-1985 and find that plausible measures of risk are more closely related to expected returns derived from a constant growth model than to those derived from multistage growth models. These findings illustrate empirical difficulties in finding empirical proxies for multistage growth models for large samples.

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mance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm.[5] Representative of industry practice, IBES contains estimates of (*i*) EPS for the upcoming fiscal years (up to five separate years), and (*ii*) a five-year growth rate in EPS. Each item is available at monthly intervals.

The mean value of individual analysts' forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[6] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base.

Dividend and other firm-specific information come from COMPUSTAT. Interest rates (both government and corporate) are gathered from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard & Poor's 500 stock (S&P 500) index, plus approximately 100 additional stocks of regulated companies. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the 113-month period from January 1982 to May 1991.

III. Risk Premia and Required Rates of Return

A. Construction of Risk Premia

For each month, a "market" required rate of return is calculated using each dividend paying stock in the S&P 500 index for which data are available. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market required return.[7] The return is converted to a risk premium

Exhibit 1. Variable Definitions

k	=	Equity required rate of return.
P_0	=	Average daily price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.[a]
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i_{lt}	=	Yield to maturity on long-term U.S. government obligations (source: Federal Reserve Bulletin, constant maturity series).
i_c	=	Yield to maturity on long-term corporate bonds: Moody's average.[b]
rp	=	Equity risk premium calculated as $rp = k - i$.
β	=	beta, calculated from CRSP monthly data over 60 months.

Notes:
[a]See footnote 7 for a discussion of the $(1 + g)$ adjustment.
[b]The average corporate bond yield across bond rating categories as reported by Moody's. See *Moody's Bond Survey* for a brief description and the latest published list of bonds included in the bond rating categories.

[5]Harris [12] provides a discussion of IBES data and its limitations. In more recent years, IBES has begun collecting forecasts for each of the next five years. Since this work was completed, the FAF used here have become available from IBES Inc., now a subsidiary of CitiBank.

[6]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same.

[7]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke and Zumwalt [15]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grow at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data with a quarterly growth rate and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in the risk class).
In this work, D_1 is calculated as D_0 $(1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "1/2 g" adjustment would allow for growth, and the remaining "1/2 g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecast of such a detailed nature exists, such a procedure is not possible. To get a feel for the magnitudes involved, during the sample period the dividend yield (D_1/P_0) and growth (market value weighted) for the S&P 500 were typically 4% to 6% and 11% to 13%, respectively. As a result, a "full g" adjustment on average increases the required return by 60 to 70 basis points (relative to no g adjustment).

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Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium,[a] 1982-1991

	Bond Market Yields[b]		Equity Market Required Return[c]	Equity Risk Premium	
Year	(1) U.S. Gov't	(2) Moody's Corporates	(3) S&P 500	U.S. Gov't (3) - (1)	Moody's Corporates (3) - (2)
1982	12.92	14.94	20.08	7.16	5.14
1983	11.34	12.78	17.89	6.55	5.11
1984	12.48	13.49	17.26	4.78	3.77
1985	10.97	12.05	16.32	5.37	4.28
1986	7.85	9.71	15.09	7.24	5.38
1987	8.58	9.84	14.71	6.13	4.86
1988	8.96	10.18	15.37	6.41	5.19
1989	8.46	9.66	15.06	6.60	5.40
1990	8.61	9.77	15.69	7.08	5.92
1991[d]	8.21	9.41	15.61	7.40	6.20
Average[e]	9.84	11.18	16.31	6.47	5.13

Notes:
[a]Values are averages of monthly figures in percent.
[b]Yields to maturity.
[c]Required return on value weighted S&P 500 index using Equation (1).
[d]Figures for 1991 are through May.
[e]Months weighted equally.

over government bonds by subtracting i_{lt}, the yield to maturity on long-term government bonds. A risk premium over corporate bond yields is also constructed by subtracting i_c, the yield on long-term corporate bonds. Exhibit 2 reports the results by year (averages of monthly data).

The results are quite consistent with the patterns reported earlier (i.e., Harris [12]). The estimated risk premia in Exhibit 2 are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1991) over government bonds is 6.47%, only slightly higher than the 6.16% average for 1982 to 1984 reported earlier (Harris [12]). Furthermore, Exhibit 2 shows the estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities.

For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 falls roughly midway between the arithmetic (7.5%) and geometric (5.7%) long-term differentials between returns on stocks and long-term government bonds. Note, however, that the expectational risk premia appear to change over time. In the following sections, we examine the estimated risk premia to see if they vary cross-sectionally with the risk of individual stocks and over time with financial market conditions.

B. Cross-Sectional Tests

Earlier, Harris [12] conducted crude tests of whether expectational equity risk premia varied with risk proxied by bond ratings and the dispersion of analysts' forecasts and found that required returns increased with higher risk. Here we examine the link between these premia and beta, perhaps the most commonly used measure of risk for equities.[8] In keeping with traditional work in this area, we adopt the methodology introduced by Fama and Macbeth [9] but replace realized returns with expected returns from Equation (2) as the variable to be explained. For this portion of our tests, we restrict our sample to 1982-1987

[8]For other efforts using expectational data in the context of the two-parameter CAPM, see Friend, Westerfield, and Granito [10], Cragg and Malkiel [7], Marston, Crawford, and Harris [19], Marston and Harris [20], and Linke, Kannan, Whitford, and Zumwalt [16]. For a more complete treatment of the subject, see Marston and Harris [20] from which we draw some of these results. Marston and Harris also investigate the role of unsystematic risk and the difference in estimates found when using expected versus realized returns.

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Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the U.S., 1926-1989

Historical Return Realizations	Geometric	Arithmetic
Common stock	10.3%	12.4%
Long-term government bonds	4.6%	4.9%
Long-term corporate bonds	5.2%	5.5%
Treasury bills	3.6%	3.7%
Inflation rate	3.1%	3.2%

Source: Ibbotson Associates, Inc., *1990 Stocks, Bonds, Bills and Inflation*, 1990 Yearbook.

and in any month include firms that have at least three forecasts of earnings growth to reduce measurement error associated with individual forecasts.[9] This restricted sample still consists of, on average, 399 firms for each of the 72 months (or 28,744 company months).

For a given company in a given month, beta is estimated via the market model (using ordinary least squares) on the prior 60 months of return data taken from CRSP. Beta estimates are updated monthly and are calculated against an equally weighted index of all NYSE securities. For each month, we aggregate firms into 20 portfolios (consisting of approximately 20 securities each). The advantage of grouped data is the reduction in potential measurement error inherent in independent variables at the company level. Portfolios are formed based on a ranking of beta estimated from a prior time period (t = -61 to t = -120). Portfolio expected returns and beta are calculated as the simple averages for the individual securities.

Using these data, we estimate the following model for each of the 72 months:

$$R_p = \alpha_0 + \alpha_1 \beta_p + u_p, \quad p = 1...20, \qquad (3)$$

where:

R_p = Expected return for portfolio p in the given month,

β_p = Portfolio beta, estimated over 60 prior months, and

u_p = A random error term with mean zero.

As a result of estimating regression (3) for each month, 72 estimates of each coefficient (α_0 and α_1) are obtained. Using realized returns as the dependent variable, the traditional approach (e.g., Fama and Macbeth [9]) is to assume that realized returns are a fair game. Given this assumption, the mean of the 72 values of each coefficient is an unbiased estimate of the mean over that same time period if one could have actually used expected returns as the dependent variable. Note that if expected returns are used as the dependent variable the fair-game assumption is not required. Making the additional assumption that the true value of the coefficient is constant over the 72 months, a test of whether the mean coefficient is different from zero is performed using a t-statistic where the denominator is the standard error of the 72 values of the coefficient. This is the technique employed by Fama and Macbeth [9]. If one assumes the CAPM is correct, the coefficient α_1 is an empirical estimate of the market risk premium, which should be positive.

To test the sensitivity of the results, we also repeat our procedures using individual security returns rather than portfolios. To account, at least in part, for differences in precision of coefficient estimates in different months we also report results in which monthly parameter estimates are weighted inversely by the standard error of the coefficient estimate rather than being weighted equally (following Chan, Hamao, and Lakonishok [6]).

Exhibit 4 shows that there is a significant positive link between expectational required returns and beta. For instance, in Panel A, the mean coefficient of 2.78 on beta is significantly different from zero at better than the 0.001 level (t = 35.31), and each of the 72 monthly coefficients going into this average is positive (as shown by that 100% positive figure). Using individual stock returns, the significant positive link between beta and expected return remains, though it is smaller in magnitude than for portfolios.[10] Comparison of Panels A and B shows that the results are not sensitive to the weighting of monthly coefficients.

While the findings in Exhibit 4 suggest a strong positive link between beta and risk premia (a result often not supported when realized returns are used as a proxy for expectations; e.g., see Tinic and West [22]), the results do not support the predictions of a simple CAPM. In particular, the intercept is higher than a proxy for the risk-free rate over the sample period and the coefficient of beta is well below estimates of a market risk premium obtained from either expectational (Exhibit 2) or historical data (Exhibit

[9]Firms for which the standard deviation of individual FAF exceeded 20 in any month were excluded since we suspect some of these involve errors in data entry. This screen eliminated very few companies in any month. The 1982-1987 period was chosen due to the availability of data on betas.

[10]The smaller coefficients on beta using individual stock portfolio returns are likely due in part to the higher measurement error in measuring individual stock versus portfolio betas.

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Exhibit 4. Mean Values of Monthly Parameter Estimates for the Relationship Between Required Returns and Beta for Both Portfolios and Individual Securities (Figures in Parentheses are *t* Values and Percent Positive), 1982-1987

	Intercept	B	Adjusted R^2 [c]	F[c]
Panel A. Equal Weighting[a]				
Portfolio returns	14.06 (54.02, 100)	2.78 (35.31, 100)	0.503	25.4
Security returns	14.77 (58.10, 100)	1.91 (16.50, 99)	0.080	39.0
Panel B. Weighted by Standard Errors[b]				
Portfolio returns	13.86 (215.6, 100)	2.67 (35.80, 100)	0.503	25.4
Security returns	14.63 (398.9, 100)	1.92 (47.3, 99)	0.080	39.0

[a]Equally weighted average of monthly parameters estimated using cross-sectional data for each of the 72 months, January 1982 - December 1987.
[b]In obtaining the reported means, estimates of the monthly intercept and slope coefficients are weighted inversely by the standard error of the estimate from the cross-sectional regression for that month.
[c]Values are averages for the 72 monthly regressions.

3).[11] Nonetheless, the results show that the estimated risk premia conform to the general theoretical relationship between risk and required return that is expected when investors are risk-averse.

C. Time Series Tests — Changes in Market Risk Premia

A potential benefit of using ex ante risk premia is the estimation of changes in market risk premia over time. With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk. For example, during the high interest rate period of the early 1980s, the high level of interest rate volatility made fixed income investments more risky holdings than they were in a world of relatively stable rates.

Studying changes in risk premia for utility stocks, Brigham, et al [4] conclude that, prior to 1980, utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. Studying risk premia for both utilities and the equity market generally, Harris [12] also reports that risk premia appear to change over time. Specifically, he finds that equity risk premia decreased with the level of government interest rates, increased with the increases in the spread between corporate and government bond yields, and increased with increases in the dispersion of analysts' forecasts. Harris' study is, however, restricted to the 36-month period, 1982 to 1984.

Exhibit 5 reports results of analyzing the relationship between equity risk premia, interest rates, and yield spreads between corporate and government bonds. Following Harris [12], these bond yield spreads are used as a time series proxy for equity risk. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders. All regressions in Exhibit 5 are corrected for serial correlation.[12]

[11]Estimation difficulties confound precise interpretation of the intercept as the risk-free rate and the coefficient on beta as the market risk premium (see Miller and Scholes [21], and Black, Jensen, and Scholes [2]). The higher than expected intercept and lower than expected slope coefficient on beta are consistent with the prior studies of Black, Jensen, and Scholes [2], and Fama and MacBeth [9] using historical returns. Such results are consistent with Black's [1] zero beta model, although alternative explanations for these findings exist as well (as noted by Black, Jensen, and Scholes [2]).

[12]Ordinary least squares regressions showed severe positive autocorrelation in many cases, with Durbin Watson statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [14, pp. 321-325].

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Exhibit 5. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value); Dependent Variable is Equity Risk Premium

Time period	Intercept	i_{lt}	$i_c - i_{lt}$	R^2
A. May 1991-1992	0.131	-0.651		0.53
	(19.82)	(-11.16)		
	0.092	-0.363	0.666	0.54
	(14.26)	(-6.74)	(5.48)	
B. 1982-1984	0.140	-0.637		0.43
	(8.15)	(-5.00)		
	0.064	-0.203	1.549	0.60
	(3.25)	(-1.63)	(4.84)	
C. 1985-1987	0.131	-0.739		0.74
	(7.73)	(-9.67)		
	0.110	-0.561	0.317	0.77
	(12.53)	(-7.30)	(1.87)	
D. 1988-1991	0.136	-0.793		0.68
	(16.23)	(-8.29)		
	0.130	-0.738	0.098	0.68
	(8.71)	(-4.96)	(0.40)	

Note: All variables are defined in Exhibit 1. Regressions were estimated using monthly data and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression, variables are expressed in decimal form, e.g., 14% = 0.14.

For the entire sample period, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by yields on government bonds, i_{lt}. This negative relationship is also true for each of the subperiods displayed in Panels B through D. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

For the entire 1982 to 1991 period, the addition of the yield spread risk proxy to the regressions dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 2 of Panel A. Furthermore, the coefficient of the yield spread (0.666) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate activity is translated into a lower equity market risk premium. Further examination of Panels B through D, however, suggests that the yield spread variable is much more important in explaining changes in equity risk premia in the early portion of the 1980s than in the 1988 to 1991 period.

In summary, market equity risk premia change over time and appear inversely related to the level of government interest rates but positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds.

IV. Conclusions

Shareholder required rates of return and risk premia are based on theories about investors' expectations for the future. In practice, however, risk premia are often estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. At least for the decade studied (1982 to 1991), the resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1989) in historical returns between stocks and bonds. There is strong evidence, however, that market risk premia change over time and, as a result, use of a constant historical average risk premium is not likely to mirror changes in investor return requirements. The results also show that the expectational risk premia vary cross-sectionally with the relative risk (beta) of individual stocks.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (e.g., portfolios of utility stocks) appropriate for a particular decision as well as analyze changes in equity return requirements over time.

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Investor growth expectations: Analysts vs. history

Analysts' growth forecasts dominate past trends in predicting stock prices.

James H. Vander Weide and Willard T. Carleton

For the purposes of implementing the Discounted Cash Flow (DCF) cost of equity model, the analyst must know which growth estimate is embodied in the firm's stock price. A study by Cragg and Malkiel (1982) suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. The Cragg and Malkiel study is based on data for the 1960s, however, a decade that was considerably more stable than the recent past.

As the issue of which growth rate to use in implementing the DCF model is so important to applications of the model, we decided to investigate whether the Cragg and Malkiel conclusions continue to hold in more recent periods. This paper describes the results of our study.

STATISTICAL MODEL

The DCF model suggests that the firm's stock price is equal to the present value of the stream of dividends that investors expect to receive from owning the firm's shares. Under the assumption that investors expect dividends to grow at a constant rate, g, in perpetuity, the stock price is given by the following simple expression:

$$P_s = \frac{D(1+g)}{k-g} \qquad (1)$$

where:

P_s = current price per share of the firm's stock;

D = current annual dividend per share;

g = expected constant dividend growth rate; and

k = required return on the firm's stock.

Dividing both sides of Equation (1) by the firm's current earnings, E, we obtain:

$$\frac{P_s}{E} = \frac{D}{E} \cdot \frac{(1+g)}{k-g} \qquad (2)$$

Thus, the firm's price/earnings (P/E) ratio is a nonlinear function of the firm's dividend payout ratio (D/E), the expected growth in dividends (g), and the required rate of return.

To investigate what growth expectation is embodied in the firm's current stock price, it is more convenient to work with a linear approximation to Equation (2). Thus, we will assume that:

$$P/E = a_0(D/E) + a_1 g + a_2 k. \qquad (3)$$

(Cragg and Malkiel found this assumption to be reasonable throughout their investigation.)

Furthermore, we will assume that the required

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rate of return, k, in Equation (3) depends on the values of the risk variables B, Cov, Rsq, and Sa, where B is the firm's Value Line beta; Cov is the firm's pretax interest coverage ratio; Rsq is a measure of the stability of the firm's five-year historical EPS; and Sa is the standard deviation of the consensus analysts' five-year EPS growth forecast for the firm. Finally, as the linear form of the P/E equation is only an approximation to the true P/E equation, and B, Cov, Rsq, and Sa are only proxies for k, we will add an error term, e, that represents the degree of approximation to the true relationship.

With these assumptions, the final form of our P/E equation is as follows:

$$P/E = a_0(D/E) + a_1 g + a_2 B + a_3 Cov + a_4 Rsq + a_5 Sa + e. \quad (4)$$

The purpose of our study is to use more recent data to determine which of the popular approaches for estimating future growth in the Discounted Cash Flow model is embodied in the market price of the firm's shares.

We estimated Equation (4) to determine which estimate of future growth, g, when combined with the payout ratio, D/E, and risk variables B, Cov, Rsq, and Sa, provides the best predictor of the firm's P/E ratio. To paraphrase Cragg and Malkiel, we would expect that growth estimates found in the best-fitting equation more closely approximate the expectation used by investors than those found in poorer-fitting equations.

DESCRIPTION OF DATA

Our data sets include both historically based measures of future growth and the consensus analysts' forecasts of five-year earnings growth supplied by the Institutional Brokers Estimate System of Lynch, Jones & Ryan (IBES). The data also include the firm's dividend payout ratio and various measures of the firm's risk. We include the latter items in the regression, along with earnings growth, to account for other variables that may affect the firm's stock price.

The data include:

Earnings Per Share. Because our goal is to determine which earnings variable is embodied in the firm's market price, we need to define this variable with care. Financial analysts who study a firm's financial results in detail generally prefer to "normalize" the firm's reported earnings for the effect of extraordinary items, such as write-offs of discontinued operations, or mergers and acquisitions. They also attempt, to the extent possible, to state earnings for different firms using a common set of accounting conventions.

We have defined "earnings" as the consensus analyst estimate (as reported by IBES) of the firm's earnings for the forthcoming year.[1] This definition approximates the normalized earnings that investors most likely have in mind when they make stock purchase and sell decisions. It implicitly incorporates the analysts' adjustments for differences in accounting treatment among firms and the effects of the business cycle on each firm's results of operations. Although we thought at first that this earnings estimate might be highly correlated with the analysts' five-year earnings growth forecasts, that was not the case. Thus, we avoided a potential spurious correlation problem.

Price/Earnings Ratio. Corresponding to our definition of "earnings," the price/earnings ratio (P/E) is calculated as the closing stock price for the year divided by the consensus analyst earnings forecast for the forthcoming fiscal year.

Dividends. Dividends per share represent the common dividends declared per share during the calendar year, after adjustment for all stock splits and stock dividends). The firm's dividend payout ratio is then defined as common dividends per share divided by the consensus analyst estimate of the earnings per share for the forthcoming calendar year (D/E). Although this definition has the deficiency that it is obviously biased downward — it divides this year's dividend by next year's earnings — it has the advantage that it implicitly uses a "normalized" figure for earnings. We believe that this advantage outweighs the deficiency, especially when one considers the flaws of the apparent alternatives. Furthermore, we have verified that the results are insensitive to reasonable alternative definitions (see footnote 1).

Growth. In comparing historically based and consensus analysts' forecasts, we calculated forty-one different historical growth measures. These included the following: 1) the past growth rate in EPS as determined by a log-linear least squares regression for the latest year,[2] two years, three years, . . ., and ten years; 2) the past growth rate in DPS for the latest year, two years, three years, . . ., and ten years; 3) the past growth rate in book value per share (computed as the ratio of common equity to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; 4) the past growth rate in cash flow per share (computed as the ratio of pretax income, depreciation, and deferred taxes to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; and 5) plowback growth (computed as the firm's retention ratio for the current year times the firm's latest annual return on common equity).

We also used the five-year forecast of earnings

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per share growth compiled by IBES and reported in mid-January of each year. This number represents the consensus (i.e., mean) forecast produced by analysts from the research departments of leading Wall Street and regional brokerage firms over the preceding three months. IBES selects the contributing brokers "because of the superior quality of their research, professional reputation, and client demand" (IBES *Monthly Summary Book*).

Risk Variables. Although many risk factors could potentially affect the firm's stock price, most of these factors are highly correlated with one another. As shown above in Equation (4), we decided to restrict our attention to four risk measures that have intuitive appeal and are followed by many financial analysts: 1) B, the firm's beta as published by Value Line; 2) Cov, the firm's pretax interest coverage ratio (obtained from Standard & Poor's Compustat); 3) Rsq, the stability of the firm's five-year historical EPS (measured by the R^2 from a log-linear least squares regression); and 4) Sa, the standard deviation of the consensus analysts' five-year EPS growth forecast (mean forecast) as computed by IBES.

After careful analysis of the data used in our study, we felt that we could obtain more meaningful results by imposing six restrictions on the companies included in our study:

1. Because of the need to calculate ten-year historical growth rates, and because we studied three different time periods, 1981, 1982, and 1983, our study requires data for the thirteen-year period 1971-1983. We included only companies with at least a thirteen-year operating history in our study.
2. As our historical growth rate calculations were based on log-linear regressions, and the logarithm of a negative number is not defined, we excluded all companies that experienced negative EPS during any of the years 1971-1983.
3. For similar reasons, we also eliminated companies that did not pay a dividend during any one of the years 1971-1983.
4. To insure comparability of time periods covered by each consensus earnings figure in the P/E ratios, we eliminated all companies that did not have a December 31 fiscal year-end.
5. To eliminate distortions caused by highly unusual events that distort current earnings but not expected future earnings, and thus the firm's price/earnings ratio, we eliminated any firm with a price/earnings ratio greater than 50.
6. As the evaluation of analysts' forecasts is a major part of this study, we eliminated all firms that IBES did not follow.

Our final sample consisted of approximately sixty-five utility firms.[3]

RESULTS

To keep the number of calculations in our study to a reasonable level, we performed the study in two stages. In Stage 1, all forty-one historically oriented approaches for estimating future growth were correlated with each firm's P/E ratio. In Stage 2, the historical growth rate with the highest correlation to the P/E ratio was compared to the consensus analyst growth rate in the multiple regression model described by Equation (4) above. We performed our regressions for each of three recent time periods, because we felt the results of our study might vary over time.

First-Stage Correlation Study

Table 1 gives the results of our first-stage correlation study for each group of companies in each of the years 1981, 1982, and 1983. The values in this table measure the correlation between the historically oriented growth rates for the various time periods and the firm's end-of-year P/E ratio.

The four variables for which historical growth rates were calculated are shown in the left-hand column: EPS indicates historical earnings per share growth, DPS indicates historical dividend per share growth, BVPS indicates historical book value per share growth, and CFPS indicates historical cash flow per share growth. The term "plowback" refers to the product of the firm's retention ratio in the currennt year and its return on book equity for that year. In all, we calculated forty-one historically oriented growth rates for each group of firms in each study period.

The goal of the first-stage correlation analysis was to determine which historically oriented growth rate is most highly correlated with each group's year-end P/E ratio. Eight-year growth in CFPS has the highest correlation with P/E in 1981 and 1982, and ten-year growth in CFPS has the highest correlation with year-end P/E in 1983. In all cases, the plowback estimate of future growth performed poorly, indicating that — contrary to generally held views — plowback is not a factor in investor expectations of future growth.

Second-Stage Regression Study

In the second stage of our regression study, we ran the regression in Equation (4) using two different measures of future growth, g: 1) the best historically oriented growth rate (g_h) from the first-stage correlation study, and 2) the consensus analysts' forecast (g_a) of five-year EPS growth. The regression results, which are shown in Table 2, support at least

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TABLE 1

Correlation Coefficients of All Historically Based Growth Estimates by Group and by Year with P/E

Current Year	*Historical Growth Rate Period in Years* 1	2	3	4	5	6	7	8	9	10
1981										
EPS	−0.02	0.07	0.03	0.01	0.03	0.12	0.08	0.09	0.09	0.09
DPS	0.05	0.18	0.14	0.15	0.14	0.15	0.19	0.23	0.23	0.23
BVPS	0.01	0.11	0.13	0.13	0.16	0.18	0.15	0.15	0.15	0.15
CFPS	−0.05	0.04	0.13	0.22	0.28	0.31	0.30	0.31	−0.57	−0.54
Plowback	0.19									
1982										
EPS	−0.10	−0.13	−0.06	−0.02	−0.02	−0.01	−0.03	−0.03	0.00	0.00
DPS	−0.19	−0.10	0.03	0.05	0.07	0.08	0.09	0.11	0.13	0.13
BVPS	0.07	0.08	0.11	0.11	0.09	0.10	0.11	0.11	0.09	0.09
CFPS	−0.02	−0.08	0.00	0.10	0.16	0.19	0.23	0.25	0.24	0.07
Plowback	0.04									
1983										
EPS	−0.06	−0.25	−0.25	−0.24	−0.16	−0.11	−0.05	0.00	0.02	0.02
DPS	0.03	−0.10	−0.03	0.08	0.15	0.21	0.21	0.21	0.22	0.24
BVPS	0.03	0.10	0.04	0.09	0.15	0.16	0.19	0.21	0.22	0.21
CFPS	−0.08	0.01	0.02	0.08	0.20	0.29	0.35	0.38	0.40	0.42
Plowback	−0.08									

two general conclusions regarding the pricing of equity securities.

First, we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. In every case, the R^2 in the regression containing the consensus analysts' forecast is higher than the R^2 in the regression containing the historical growth measure. The regression coefficients in the equation containing the consensus analysts' forecast also are considerably more significant than they are in the alternative regression. These results are consistent with those found by Cragg and Malkiel for data covering the period 1961-1968. Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy–and–sell decisions.

TABLE 2

Regression Results
Model I

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−6.42*	10.31*	7.67*	3.24	0.54*	1.42*	57.43	0.83	46.49
	(5.50)	(14.79)	(2.20)	(2.86)	(2.50)	(2.85)	(4.07)		
1982	−2.90*	9.32*	8.49*	2.85	0.45*	−0.42	3.63	0.86	65.53
	(2.75)	(18.52)	(4.18)	(2.83)	(2.60)	(0.05)	(0.26)		
1983	−5.96*	10.20*	19.78*	4.85	0.44*	0.33	32.49	0.82	45.26
	(3.70)	(12.20)	(4.83)	(2.95)	(1.89)	(0.50)	(1.29)		

Part B: *Analysis*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−4.97*	10.62*	54.85*	−0.61	0.33*	0.63*	4.34	0.91	103.10
	(6.23)	(21.57)	(8.56)	(0.68)	(2.28)	(1.74)	(0.37)		
1982	−2.16*	9.47*	50.71*	−1.07	0.36*	−0.31	119.05*	0.90	97.62
	(2.59)	(22.46)	(9.31)	(1.14)	(2.53)	(1.09)	(1.60)		
1983	−8.47*	11.96*	79.05*	2.16	0.56*	0.20	−34.43	0.87	69.81
	(7.07)	(16.48)	(7.84)	(1.55)	(3.08)	(0.38)	(1.44)		

Notes:

* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

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Second, there is some evidence that investors tend to view risk in traditional terms. The interest coverage variable is statistically significant in all but one of our samples, and the stability of the operating income variable is statistically significant in six of the twelve samples we studied. On the other hand, the beta is never statistically significant, and the standard deviation of the analysts' five-year growth forecasts is statistically significant in only two of our twelve samples. This evidence is far from conclusive, however, because, as we demonstrate later, a significant degree of cross-correlation among our four risk variables makes any general inference about risk extremely hazardous.

Possible Misspecification of Risk

The stock valuation theory says nothing about which risk variables are most important to investors. Therefore, we need to consider the possibility that the risk variables of our study are only proxies for the "true" risk variables used by investors. The inclusion of proxy variables may increase the variance of the parameters of most concern, which in this case are the coefficients of the growth variables.[4]

To allow for the possibility that the use of risk proxies has caused us to draw incorrect conclusions concerning the relative importance of analysts' growth forecasts and historical growth extrapolations, we have also estimated Equation (4) with the risk variables excluded. The results of these regressions are shown in Table 3.

Again, there is overwhelming evidence that the consensus analysts' growth forecast is superior to the historically oriented growth measures in predicting the firm's stock price. The R^2 and t-statistics are higher in every case.

TABLE 3

Regression Results
Model II

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	−1.05	9.59	21.20	0.73	82.95
	(1.61)	(12.13)	(7.05)		
1982	0.54	8.92	12.18	0.83	167.97
	(1.38)	(17.73)	(6.95)		
1983	−0.75	8.92	12.18	0.77	107.82
	(1.13)	(12.38)	(7.94)		

Part B: *Analysis*

$P/E + a_0 + a_1 D/E + a_2 g_a$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	3.96	10.07	60.53	0.90	274.16
	(8.31)	(8.31)	(20.91)	(15.79)	
1982	−1.75	9.19	44.92	0.88	246.36
	(4.00)	(4.00)	(21.35)	(11.06)	
1983	−4.97	10.95	82.02	0.83	168.28
	(6.93)	(6.93)	(15.93)	(11.02)	

Notes:
* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

CONCLUSION

The relationship between growth expectations and share prices is important in several major areas of finance. The data base of analysts' growth forecasts collected by Lynch, Jones & Ryan provides a unique opportunity to test the hypothesis that investors rely more heavily on analysts' growth forecasts than on historical growth extrapolations in making security buy–and–sell decisions. With the help of this data base, our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.

[1] We also tried several other definitions of "earnings," including the firm's most recent primary earnings per share prior to any extraordinary items or discontinued operations. As our results were insensitive to reasonable alternative definitions of "earnings" we report only the results for the IBES consensus.

[2] For the latest year, we actually employed a point-to-point growth calculation because there were only two available observations.

[3] We use the word "approximately," because the set of available firms varied each year. In any case, the number varied only from zero to three firms on either side of the figures cited here.

[4] See Maddala (1977).

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SSgA
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INVESTOR GROWTH EXPECTATIONS

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A study done by Vander Weide and Carleton in 1988[1] suggests that consensus analysts' forecast of future growth is superior to historically oriented growth measures in stock valuation process for domestic companies. We worked with one of the original authors of the study, Dr. James H. Vander Weide, and closely followed his suggestions and methodology to investigate whether the results still hold in more recent times (2001- 2003).

We used the following equation to determine which estimate of future growth (g) best predicts the firm's P/E ratio when combined with the dividend payout ratio, D/E, and risk variables, B, Cov, Stb, and Sa.

$$P/E = a_0(D/E) + a_1 g(\text{Growth}) + a_2 B(\text{Beta}) + a_3 \text{Cov}(\text{Interest Coverage Ratio}) + a_4 \text{Stb}(\text{Stability}) + a_5 \text{Sa}(\text{Std Dev}) + e$$

Data Description

Earnings Per Share: IBES consensus analyst estimate of the firm's earnings for the unreported year.

Price/Earnings Ratio: Closing stock price for the year divided by the consensus analyst earnings per share for the forthcoming year.

Dividends: Ratio of common dividends per share to the consensus analyst earnings forecast for the forthcoming fiscal year (D/E).

Historical Growth measures

EPS Growth Rate: Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.

Dividend per Share Growth Rate: Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.

Book Value per Share Growth Rate: Common equity divided by the common shares outstanding. Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.

Cash Flow per Share Growth Rate: Ratio of gross cash flow to common shares outstanding. Determined by a log-linear least squares regression for the latest year, two years, three years, …, and ten years.

Plowback Growth: Firm's retention ratio for the current year times the firm's latest annual return on equity.

3yr Plowback Growth: Firm's three-year average retention ratio times the firm's three-year average return on equity.

Consensus Analysts' Forecasts

Five-Year Earnings Per Share Growth: Mean analysts' forecast compiled by IBES.

[1] Vander Weide, J. H., and W. T. Carleton. "Investor Growth Expectations: Analysts vs. History." *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

Risk Variables

B: Beta, the firm's beta versus NYSE from Value Line.

Cov: The firm's pretax interest coverage ratio from Compustat.

Stb: Five-year historical earnings per share stability. Average absolute percentage difference between actual reported EPS and a 5yr historical EPS growth trend line from IBES.

Sa: The standard deviation of earnings per share estimate for the fiscal year from IBES.

We set five restrictions on the companies included in the study in order to be consistent with the original study and to obtain more meaningful results.

- Excluded all firms that IBES did not follow.
- Eliminated companies with:
  - Negative EPS during any of the years 1991-2003.
  - No dividend during any one of the years 1991-2003.
  - P/E ratio greater than 60 in years 2001-2003.
  - Less than five years of operating history.

The final universe consisted of 411 US firms, fifty-nine of which are utility companies.

Results

The study was performed in two stages.

Stage 1

In order to determine which historically oriented growth measure is most highly correlated with each firm's end-of-year P/E ratio, we computed spearman (rank) correlations between all forty-two historically oriented future growth measures and P/E.

The result of the stage 1 study is displayed in Table 1. Three-year plowback ratio has the highest correlation with P/E in 2001 and 2002, and five-year EPS growth rate has the highest correlation with P/E in 2003.

Table 1

Stage1 Results for Utility and Non-Utility Companies Combined

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.232	0.210	0.145	0.122	0.059	0.034	-0.007	-0.076	-0.117	-0.154
	DPS	-0.243	-0.297	-0.296	-0.293	-0.313	-0.316	-0.336	-0.334	-0.329	-0.333
	BVPS	0.059	-0.017	-0.098	-0.138	-0.150	-0.182	-0.219	-0.259	-0.271	-0.273
	CFPS	0.092	0.092	0.087	0.042	-0.063	-0.102	-0.141	-0.193	-0.237	-0.262
	plowback	0.203									
	plowback3	0.308									
2002	EPS	-0.007	0.147	0.076	0.080	0.083	0.050	0.030	-0.018	-0.060	-0.089
	DPS	-0.126	-0.202	-0.251	-0.224	-0.215	-0.239	-0.232	-0.233	-0.211	-0.198
	BVPS	-0.036	-0.036	-0.078	-0.115	-0.114	-0.127	-0.152	-0.162	-0.175	-0.171
	CFPS	0.056	0.045	0.017	0.021	0.030	-0.024	-0.050	-0.080	-0.125	-0.162
	plowback	0.093									
	plowback3	0.180									
2003	EPS	0.073	0.084	0.214	0.231	0.244	0.228	0.182	0.158	0.104	0.049
	DPS	0.120	0.054	-0.001	-0.078	-0.090	-0.126	-0.152	-0.165	-0.183	-0.185
	BVPS	0.097	0.076	0.067	0.036	-0.045	-0.062	-0.063	-0.083	-0.105	-0.131
	CFPS	0.146	0.196	0.243	0.239	0.206	0.178	0.107	0.089	0.039	-0.022
	plowback	-0.017									
	plowback3	0.038									

We also independently examined utility and non-utility firms. Table 2 shows the result for the fifty-nine utility firms. Two-year growth in EPS has the highest correlation with P/E in 2001, four-year EPS has the highest correlation in 2002, and six-year EPS has the highest correlation in 2003.

Table 3 exhibits the result for the remaining non-utility firms. EPS one-year growth, two-year growth, and five-year growth has the highest correlation with P/E in 2001, 2002, and 2003, respectively.

Table 2

Stage1 Results for Utility Companies

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.305	0.330	0.305	0.319	0.238	0.157	0.129	0.107	0.079	0.048
	DPS	-0.215	-0.321	-0.302	-0.294	-0.316	-0.281	-0.332	-0.414	-0.435	-0.429
	BVPS	0.164	0.137	0.147	-0.027	-0.072	-0.135	-0.117	-0.104	-0.106	-0.140
	CFPS	0.194	0.135	0.020	-0.018	-0.122	-0.157	-0.135	-0.134	-0.103	-0.219
	plowback	-0.143									
	plowback3	-0.027									
2002	EPS	-0.065	0.044	0.069	0.119	0.071	0.004	-0.038	-0.069	-0.061	-0.070
	DPS	-0.333	-0.327	-0.278	-0.313	-0.280	-0.321	-0.277	-0.226	-0.203	-0.210
	BVPS	-0.325	-0.239	-0.182	-0.177	-0.230	-0.237	-0.250	-0.247	-0.235	-0.235
	CFPS	-0.205	-0.132	-0.172	-0.166	-0.216	-0.289	-0.285	-0.265	-0.227	-0.218
	plowback	-0.151									
	plowback3	-0.133									
2003	EPS	0.010	0.136	0.186	0.263	0.365	0.367	0.344	0.343	0.309	0.302
	DPS	0.151	-0.029	-0.014	-0.022	-0.054	-0.117	-0.142	-0.137	-0.105	-0.092
	BVPS	0.212	0.060	0.047	0.019	0.003	0.040	0.022	0.005	0.003	-0.002
	CFPS	0.222	-0.046	0.173	0.115	0.165	0.100	0.017	0.077	0.057	0.077
	plowback	-0.365									
	plowback3	-0.403									

Table 3

Stage1 Results for Non-Utility Companies

Correlations between Historically Based Growth Estimates by Year with P/E

Current Year		y1	y2	y3	y4	y5	y6	y7	y8	y9	y10
2001	EPS	0.1843	0.1660	0.1293	0.1218	0.0873	0.0829	0.0618	0.0106	-0.0194	-0.0412
	DPS	-0.2036	-0.2211	-0.2042	-0.1935	-0.2098	-0.2066	-0.2186	-0.2155	-0.2046	-0.1975
	BVPS	0.0757	0.0084	-0.0791	-0.0997	-0.0916	-0.1146	-0.1388	-0.1783	-0.1866	-0.1823
	CFPS	0.0864	0.0710	0.0956	0.0704	-0.0033	-0.0162	-0.0366	-0.0747	-0.1186	-0.1325
	plowback	0.0781									
	plowback3	0.1781									
2002	EPS	0.0762	0.1767	0.0755	0.0817	0.0936	0.0757	0.0708	0.0316	-0.0011	-0.0254
	DPS	-0.0804	-0.1693	-0.2103	-0.1672	-0.1519	-0.1720	-0.1645	-0.1636	-0.1394	-0.1226
	BVPS	0.0527	0.0236	-0.0363	-0.0777	-0.0710	-0.0753	-0.0953	-0.1019	-0.1118	-0.1061
	CFPS	0.0905	0.0488	0.0143	0.0237	0.0563	0.0246	0.0097	-0.0079	-0.0458	-0.0821
	plowback	0.0634									
	plowback3	0.1306									
2003	EPS	0.1254	0.1783	0.2788	0.2689	0.2791	0.2622	0.2219	0.2039	0.1559	0.1090
	DPS	0.1810	0.1290	0.0655	-0.0128	-0.0101	-0.0400	-0.0630	-0.0772	-0.0930	-0.0952
	BVPS	0.1555	0.1740	0.1534	0.1056	0.0127	-0.0069	-0.0054	-0.0218	-0.0416	-0.0636
	CFPS	0.1479	0.2200	0.2512	0.2429	0.2004	0.1839	0.1349	0.1286	0.0892	0.0388
	plowback	-0.1109									
	plowback3	-0.0402									

Stage 2

We compared the multiple regression model of historical growth rate with the highest correlation to the P/E ratio from stage 1 to the five-year earnings per share growth forecast.

$$P/E = a_0(D/E) + a_1 g + a_2 B + a_3 Cov + a_4 Stb + a_5 Sa + e$$

The regression results are displayed in table 4. The results show that the consensus analysts' forecast of future growth better approximates the firm's P/E ratio, which is consistent with the results found by Vander Weide and Carleton. In both regressions, R^2 in the regression with the consensus analysts' forecast is higher than the R^2 in the regression with the historical growth.

Table 4
Stage2 Results for Utility and Non-Utility Companies Combined
Multiple Regression Results
P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	10.43	8.46	10.79	6.79	0.02	-0.03	-18.83	0.20	13.90
	4.73	5.53	2.93	3.54	3.05	-3.06	-3.32		
2002	12.36	7.60	6.66	1.01	0.00	0.01	-32.48	0.15	9.46
	7.21	6.18	2.61	0.66	1.57	1.48	-4.04		
2003	13.34	5.96	9.87	5.27	0.01	-0.01	-20.46	0.24	17.61
	7.29	4.04	2.95	3.39	3.62	-1.31	-4.25		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	-1.26	16.14	144.75	-0.64	0.01	-0.03	-10.76	0.47	48.00
	-0.62	11.63	13.22	-0.38	3.07	-4.04	-2.29		
2002	3.37	13.37	106.07	-3.60	0.00	0.01	-21.85	0.35	29.73
	1.93	10.97	10.59	-2.57	1.25	1.50	-3.06		
2003	4.77	12.76	61.93	4.38	0.01	0.00	-19.41	0.33	26.38
	2.65	9.48	7.25	3.01	2.45	-0.81	-4.33		

*T-stats below the coefficients in smaller font

For utility companies shown in table 5, consensus analysts' forecast of future growth is superior to historically oriented growth in 2002 and 2003. R^2 is lower in the regression with the consensus analysts' forecast in 2001. For non-utility companies, we found that consensus analysts' forecast of future growth is superior to the alternative in all three years (table 6).

Table 5
Stage2 Results for Utility Companies

Multiple Regression Results

P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	7.90	11.07	-11.19	-3.00	0.29	0.00	-9.37	0.44	6.38
	2.16	4.80	-5.71	-0.86	0.88	0.64	-1.51		
2002	13.87	7.00	-3.80	-6.89	0.56	0.00	-29.89	0.38	5.11
	4.02	3.54	-0.66	-2.01	1.48	0.42	-2.70		
2003	11.29	7.74	-1.65	-1.40	0.32	0.00	-5.69	0.25	2.68
	3.22	3.30	-0.23	-0.43	1.05	-0.73	-0.75		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	9.61	9.20	66.61	-7.92	0.50	-0.01	-12.83	0.27	2.95
	2.31	3.45	3.66	-1.86	1.31	-1.33	-1.76		
2002	12.43	7.86	50.74	-9.61	0.50	0.00	-24.94	0.48	7.56
	3.89	5.29	3.10	-2.94	1.50	0.17	-2.41		
2003	5.81	11.06	101.12	-1.69	-0.19	0.00	-4.75	0.50	7.81
	1.89	6.32	4.80	-0.58	-0.74	-0.22	-0.74		

*T-stats below the coefficients in smaller font

Table 6
Stage2 Results for Non-Utility Companies

Multiple Regression Results

P/E = a0 + a1 **D/E** + a2 **g** + a3 **B** + a4 **Cov** + a5 **Stb** + a6 **Sa**

Historical

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	15.90	8.39	2.82	3.53	0.02	-0.03	-21.05	0.21	12.45
	6.57	4.13	1.96	1.68	2.97	-2.14	-3.40		
2002	17.76	8.46	6.02	-3.06	0.00	0.02	-36.97	0.27	16.78
	9.39	5.19	3.28	-1.88	1.37	2.52	-4.31		
2003	14.24	9.86	8.85	3.46	0.01	0.00	-19.00	0.30	19.89
	7.49	5.89	2.49	2.11	3.23	-0.15	-3.73		

Analysts' Forecasts

	a0	a1	a2	a3	a4	a5	a6	Rsq	F Ratio
2001	-0.51	17.28	140.84	-1.06	0.01	-0.03	-8.63	0.44	36.00
	-0.22	11.21	10.73	-0.59	2.88	-2.62	-1.63		
2002	5.05	15.67	91.22	-4.06	0.00	0.02	-22.93	0.38	27.65
	2.48	11.23	7.66	-2.74	1.18	2.33	-2.87		
2003	7.25	14.47	45.60	3.47	0.01	0.00	-19.09	0.33	22.30
	3.56	9.42	4.68	2.20	2.36	-0.12	-3.89		

*T-stats below the coefficients in smaller font

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Cost of Capital Estimation

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson

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■ In the mid-1960s, Myron Gordon and others began applying the theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as comparable companies. This procedure has now been thoroughly discredited (see Robichek [15]), and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.

Our purpose in this paper is to discuss the risk-premium approach, including the market risk premium that is used in the CAPM. First, we critique the various procedures that have been used in the past to estimate risk premiums. Second, we present some data on estimated risk premiums since 1965. Third, we examine the relationship between equity risk premiums and the level of interest rates, because it is important, for purposes of estimating the cost of capital, to know just how stable the relationship between risk premiums and interest rates is over time. If stability exists, then one can estimate the cost of equity at any point in time as a function of interest rates as reported in *The Wall Street Journal*, the *Federal Reserve Bulletin*, or some similar source.[1] Fourth, while we do not discuss the CAPM directly, our analysis does have some important implications for selecting a market risk premium for use in that model. Our focus is on utilities, but the methodology is applicable to the estimation of the cost of

[1]For example, the Federal Energy Regulatory Commission's Staff recently proposed that a risk premium be estimated every two years and that, between estimation dates, the last-determined risk premium be added to the current yield on ten-year Treasury bonds to obtain an estimate of the cost of equity to an average utility (Docket RM 80–36). Subsequently, the FCC made a similar proposal ("Notice of Proposed Rulemaking," August 13, 1984, Docket No. 84–800). Obviously, the validity of such procedures depends on (i) the accuracy of the risk premium estimate and (ii) the stability of the relationship between risk premiums and interest rates. Both proposals are still under review.

equity for any publicly traded firm, and also for non-traded firms for which an appropriate risk class can be assessed, including divisions of publicly traded corporations.[2]

Alternative Procedures for Estimating Risk Premiums

In a review of both rate cases and the academic literature, we have identified three basic methods for estimating equity risk premiums: (i) the *ex post,* or historic, yield spread method; (ii) the survey method; and (iii) an *ex ante* yield spread method based on DCF analysis.[3] In this section, we briefly review these three methods.

Historic Risk Premiums

A number of researchers, most notably Ibbotson and Sinquefield [12], have calculated historic holding period returns on different securities and then estimated risk premiums as follows:

$$\text{Historic Risk Premium} = \left(\begin{array}{c}\text{Average of the annual returns on a stock index for a particular past period}\end{array}\right) - \left(\begin{array}{c}\text{Average of the annual returns on a bond index for the same past period}\end{array}\right). \quad (1)$$

Ibbotson and Sinquefield (I&S) calculated both arithmetic and geometric average returns, but most of their risk-premium discussion was in terms of the geometric averages. Also, they used both corporate and Treasury bond indices, as well as a T-bill index, and they analyzed all possible holding periods since 1926. The I&S study has been employed in numerous rate cases in two ways: (i) directly, where the I&S historic risk premium is added to a company's bond yield to obtain an estimate of its cost of equity, and (ii) indirectly, where I&S data are used to estimate the market risk premium in CAPM studies.

There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. These measurement problems are common to most forecasts based on time series data.

The Survey Approach

One obvious way to estimate equity risk premiums is to poll investors. Charles Benore [1], the senior utility analyst for Paine Webber Mitchell Hutchins, a leading institutional brokerage house, conducts such a survey of major institutional investors annually. His 1983 results are reported in Exhibit 1.

Exhibit 1. Results of Risk Premium Survey, 1983*

Assuming a double A, long-term utility bond currently yields 12½%, the common stock for the same company would be fairly priced relative to the bond if its expected return was as follows:

Total Return	Indicated Risk Premium (basis points)	Percent of Respondents
over 20½%	over 800	
20½%	800	
19½%	700	
18½%	600	10%
17½%	500	8%
16½%	400	29%
15½%	300	35%
14½%	200	16%
13½%	100	0%
under 13½%	under 100	1%
Weighted average	358	100%

*Benore's questionnaire included the first two columns, while his third column provided a space for the respondents to indicate which risk premium they thought applied. We summarized Benore's responses in the frequency distribution given in Column 3. Also, in his questionnaire each year, Benore adjusts the double A bond yield and the total returns (Column 1) to reflect current market conditions. Both the question above and the responses to it were taken from the survey conducted in April 1983.

[2]The FCC is particularly interested in risk-premium methodologies, because (i) only eighteen of the 1,400 telephone companies it regulates have publicly-traded stock, and hence offer the possibility of DCF analysis, and (ii) most of the publicly-traded telephone companies have both regulated and unregulated assets, so a corporate DCF cost might not be applicable to the regulated units of the companies.

[3]In rate cases, some witnesses also have calculated the differential between the yield to maturity (YTM) of a company's bonds and its concurrent ROE, and then called this differential a risk premium. In general, this procedure is unsound, because the YTM on a bond is a *future expected* return on the bond's *market value*, while the ROE is the *past realized* return on the stock's *book value*. Thus, comparing YTMs and ROEs is like comparing apples and oranges.

Benore's results, as measured by the average risk premiums, have varied over the years as follows:

Year	Average RP (basis points)
1978	491
1979	475
1980	423
1981	349
1982	275
1983	358

The survey approach is conceptually sound in that it attempts to measure investors' expectations regarding risk premiums, and the Benore data also seem to be carefully collected and processed. Therefore, the Benore studies do provide one useful basis for estimating risk premiums. However, as with most survey results, the possibility of biased responses and/or biased sampling always exists. For example, if the responding institutions are owners of utility stocks (and many of them are), and if the respondents think that the survey results might be used in a rate case, then they might bias upward their responses to help utilities obtain higher authorized returns. Also, Benore surveys large institutional investors, whereas a high percentage of utility stocks are owned by individuals rather than institutions, so there is a question as to whether his reported risk premiums are really based on the expectations of the "representative" investor. Finally, from a pragmatic standpoint, there is a question as to how to use the Benore data for utilities that are not rated AA. The Benore premiums can be applied as an add-on to the own-company bond yields of any given utility only if it can be assumed that the premiums are constant across bond rating classes. *A priori*, there is no reason to believe that the premiums will be constant.

DCF-Based *Ex Ante* Risk Premiums

In a number of studies, the DCF model has been used to estimate the *ex ante* market risk premium, RP_M. Here, one estimates the average expected future return on equity for a group of stocks, k_M, and then subtracts the concurrent risk-free rate, R_F, as proxied by the yield to maturity on either corporate or Treasury securities:[4]

$$RP_M = k_M - R_F. \tag{2}$$

Conceptually, this procedure is exactly like the I&S approach except that one makes direct estimates of future expected returns on stocks and bonds rather than assuming that investors expect future returns to mirror past returns.

The most difficult task, of course, is to obtain a valid estimate of k_M, the expected rate of return on the market. Several studies have attempted to estimate DCF risk premiums for the utility industry and for other stock market indices. Two of these are summarized next.

Vandell and Kester. In a recently published monograph, Vandell and Kester [18] estimated *ex ante* risk premiums for the period from 1944 to 1978. R_F was measured both by the yield on 90-day T-bills and by the yield on the Standard and Poor's AA Utility Bond Index. They measured k_M as the average expected return on the S&P's 500 Index, with the expected return on individual securities estimated as follows:

$$k_i = \left(\frac{D_1}{P_0}\right)_i + g_i, \tag{3}$$

where,

D_1 = dividend per share expected over the next twelve months,
P_0 = current stock price,
g = estimated long-term constant growth rate, and
i = the i^{th} stock.

To estimate g_i, Vandell and Kester developed fifteen forecasting models based on both exponential smoothing and trend-line forecasts of earnings and dividends, and they used historic data over several estimating horizons. Vandell and Kester themselves acknowledge that, like the Ibbotson-Sinquefield premiums, their analysis is subject to potential errors associated with trying to estimate expected future growth purely from past data. We shall have more to say about this point later.

[4]In this analysis, most people have used yields on long-term bonds rather than short-term money market instruments. It is recognized that long-term bonds, even Treasury bonds, are not risk free, so an RP_M based on these debt instruments is smaller than it would be if there were some better proxy to the long-term riskless rate. People have attempted to use the T-bill rate for R_F, but the T-bill rate embodies a different average inflation premium than stocks, and it is subject to random fluctuations caused by monetary policy, international currency flows, and other factors. Thus, many people believe that for cost of capital purposes, R_F should be based on long-term securities.

We did test to see how debt maturities would affect our calculated risk premiums. If a short-term rate such as the 30-day T-bill rate is used, measured risk premiums jump around widely and, so far as we could tell, randomly. The choice of a maturity in the 10- to 30-year range has little effect, as the yield curve is generally fairly flat in that range.

Malkiel. Malkiel [14] estimated equity risk premiums for the Dow Jones Industrials using the DCF model. Recognizing that the constant dividend growth assumption may not be valid, Malkiel used a nonconstant version of the DCF model. Also, rather than rely exclusively on historic data, he based his growth rates on Value Line's five-year earnings growth forecasts plus the assumption that each company's growth rate would, after an initial five-year period, move toward a long-run real national growth rate of four percent. He also used ten-year maturity government bonds as a proxy for the riskless rate. Malkiel reported that he tested the sensitivity of his results against a number of different types of growth rates, but, in his words, "The results are remarkably robust, and the estimated risk premiums are all very similar." Malkiel's is, to the best of our knowledge, the first risk-premium study that uses analysts' forecasts. A discussion of analysts' forecasts follows.

Security Analysts' Growth Forecasts

Ex ante DCF risk premium estimates can be based either on expected growth rates developed from time series data, such as Vandell and Kester used, or on analysts' forecasts, such as Malkiel used. Although there is nothing inherently wrong with time series-based growth rates, an increasing body of evidence suggests that primary reliance should be placed on analysts' growth rates. First, we note that the observed market price of a stock reflects the consensus view of investors regarding its future growth. Second, we know that most large brokerage houses, the larger institutional investors, and many investment advisory organizations employ security analysts who forecast future EPS and DPS, and, to the extent that investors rely on analysts' forecasts, the consensus of analysts' forecasts is embodied in market prices. Third, there have been literally dozens of academic research papers dealing with the accuracy of analysts' forecasts, as well as with the extent to which investors actually use them. For example, Cragg and Malkiel [7] and Brown and Rozeff [5] determined that security analysts' forecasts are more relevant in valuing common stocks and estimating the cost of capital than are forecasts based solely on historic time series. Stanley, Lewellen, and Schlarbaum [16] and Linke [13] investigated the importance of analysts' forecasts and recommendations to the investment decisions of individual and institutional investors. Both studies indicate that investors rely heavily on analysts' reports and incorporate analysts' forecast information in the formation of their expectations about stock returns. A representative listing of other work supporting the use of analysts' forecasts is included in the References section. Thus, evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts. Accordingly, we based our cost of equity, and hence risk premium estimates, on analysts' forecast data.[5]

Risk Premium Estimates

For purposes of estimating the cost of capital using the risk premium approach, it is necessary either that the risk premiums be time-invariant or that there exists a predictable relationship between risk premiums and interest rates. If the premiums are constant over time, then the constant premium could be added to the prevailing interest rate. Alternatively, if there exists a stable relationship between risk premiums and interest rates, it could be used to predict the risk premium from the prevailing interest rate.

To test for stability, we obviously need to calculate risk premiums over a fairly long period of time. Prior to 1980, the only consistent set of data we could find came from Value Line, and, because of the work involved, we could develop risk premiums only once a year (on January 1). Beginning in 1980, however, we began collecting and analyzing Value Line data on a monthly basis, and in 1981 we added monthly estimates from Merrill Lynch and Salomon Brothers to our data base. Finally, in mid-1983, we expanded our analysis to include the IBES data.

Annual Data and Results, 1966–1984

Over the period 1966–1984, we used Value Line data to estimate risk premiums both for the electric utility industry and for industrial companies, using the companies included in the Dow Jones Industrial and Utility averages as representative of the two groups. Value Line makes a five-year growth rate forecast, but it also gives data from which one can develop a longer-term forecast. Since DCF theory calls for a truly long-term (infinite horizon) growth rate, we concluded that it was better to develop and use such a forecast than to

[5]Recently, a new type of service that summarizes the key data from most analysts' reports has become available. We are aware of two sources of such services, the Lynch, Jones, and Ryan's Institutional Brokers Estimate System (IBES) and Zack's Icarus Investment Service. IBES and the Icarus Service gather data from both buy-side and sell-side analysts and provide it to subscribers on a monthly basis in both a printed and a computer-readable format.

Exhibit 2. Estimated Annual Risk Premiums, Nonconstant (Value Line) Model, 1966–1984

January 1 of the Year Reported	Dow Jones Electrics			Dow Jones Industrials			
	k_{Avg}	R_F	RP	k_{Avg}	R_F	RP	(3) ÷ (6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1966	8.11%	4.50%	3.61%	9.56%	4.50%	5.06%	0.71
1967	9.00%	4.76%	4.24%	11.57%	4.76%	6.81%	0.62
1968	9.68%	5.59%	4.09%	10.56%	5.59%	4.97%	0.82
1969	9.34%	5.88%	3.46%	10.96%	5.88%	5.08%	0.68
1970	11.04%	6.91%	4.13%	12.22%	6.91%	5.31%	0.78
1971	10.80%	6.28%	4.52%	11.23%	6.28%	4.95%	0.91
1972	10.53%	6.00%	4.53%	11.09%	6.00%	5.09%	0.89
1973	11.37%	5.96%	5.41%	11.47%	5.96%	5.51%	0.98
1974	13.85%	7.29%	6.56%	12.38%	7.29%	5.09%	1.29
1975	16.63%	7.91%	8.72%	14.83%	7.91%	6.92%	1.26
1976	13.97%	8.23%	5.74%	13.32%	8.23%	5.09%	1.13
1977	12.96%	7.30%	5.66%	13.63%	7.30%	6.33%	0.89
1978	13.42%	7.87%	5.55%	14.75%	7.87%	6.88%	0.81
1979	14.92%	8.99%	5.93%	15.50%	8.99%	6.51%	0.91
1980	16.39%	10.18%	6.21%	16.53%	10.18%	6.35%	0.98
1981	17.61%	11.99%	5.62%	17.37%	11.99%	5.38%	1.04
1982	17.70%	14.00%	3.70%	19.30%	14.00%	5.30%	0.70
1983	16.30%	10.66%	5.64%	16.53%	10.66%	5.87%	0.96
1984	16.03%	11.97%	4.06%	15.72%	11.97%	3.75%	1.08

use the five-year prediction.[6] Therefore, we obtained data as of January 1 from Value Line for each of the Dow Jones companies and then solved for k, the expected rate of return, in the following equation:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \left(\frac{D_n(1+g_n)}{k-g_n}\right)\left(\frac{1}{1+k}\right)^n. \qquad (4)$$

Equation (4) is the standard nonconstant growth DCF model; P_0 is the current stock price; D_t represents the forecasted dividends during the nonconstant growth period; n is the years of nonconstant growth; D_n is the first constant growth dividend; and g_n is the constant, long-run growth rate after year n. Value Line provides D_t values for t = 1 and t = 4, and we interpolated to obtain D_2 and D_3. Value Line also gives estimates for ROE and for the retention rate (b) in the terminal year, n, so we can forecast the long-term growth rate as g_n = b(ROE). With all the values in Equation (4) specified except k, we can solve for k, which is the DCF rate of return that would result if the Value Line forecasts were met, and, hence, the DCF rate of return implied in the Value Line forecast.[7]

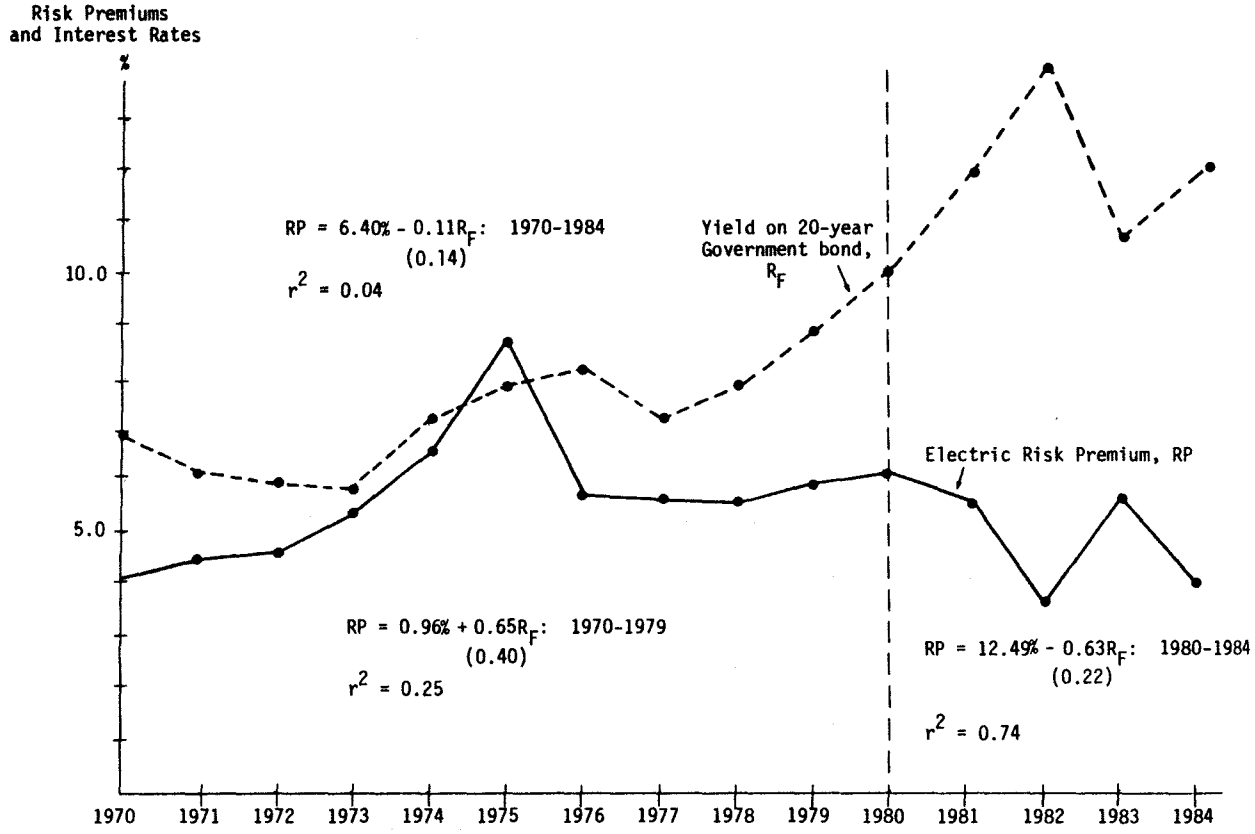
Having estimated a k value for each of the electric and industrial companies, we averaged them (using market-value weights) to obtain a k value for each group, after which we subtracted R_F (taken as the December 31 yield on twenty-year constant maturity Treasury bonds) to obtain the estimated risk premiums shown in Exhibit 2. The premiums for the electrics are plotted in Exhibit 3, along with interest rates. The following points are worthy of note:

1. Risk premiums fluctuate over time. As we shall see in the next section, fluctuations are even wider when measured on a monthly basis.
2. The last column of Exhibit 2 shows that risk premi-

[6]This is a debatable point. Cragg and Malkiel, as well as many practicing analysts, feel that most investors actually focus on five-year forecasts. Others, however, argue that five-year forecasts are too heavily influenced by base-year conditions and/or other nonpermanent conditions for use in the DCF model. We note (i) that most published forecasts do indeed cover five years, (ii) that such forecasts are typically "normalized" in some fashion to alleviate the base-year problem, and (iii) that for relatively stable companies like those in the Dow Jones averages, it generally does not matter greatly if one uses a normalized five-year or a longer-term forecast, because these companies meet the conditions of the constant-growth DCF model rather well.

[7]Value Line actually makes an explicit price forecast for each stock, and one could use this price, along with the forecasted dividends, to develop an expected rate of return. However, Value Line's forecasted stock price builds in a forecasted *change* in k. Therefore, the forecasted price is inappropriate for use in estimating current values of k.

Exhibit 3. Equity Risk Premiums for Electric Utilities and Yields on 20-Year Government Bonds, 1970–1984*



*Standard errors of the coefficients are shown in parentheses below the coefficients.

ums for the utilities increased relative to those for the industrials from the mid-1960s to the mid-1970s. Subsequently, the perceived riskiness of the two groups has, on average, been about the same.

3. Exhibit 3 shows that, from 1970 through 1979, utility risk premiums tended to have a positive association with interest rates: when interest rates rose, so did risk premiums, and vice versa. However, beginning in 1980, an inverse relationship appeared: rising interest rates led to declining risk premiums. We shall discuss this situation further in the next section.

Monthly Data and Results, 1980–1984

In early 1980, we began calculating risk premiums on a monthly basis. At that time, our only source of analysts' forecasts was Value Line, but beginning in 1981 we also obtained Merrill Lynch and Salomon Brothers' data, and then, in mid-1983, we obtained IBES data. Because our focus was on utilities, we restricted our monthly analysis to that group.

Our 1980–1984 monthly risk premium data, along with Treasury bond yields, are shown in Exhibits 4 and 5 and plotted in Exhibits 6, 7, and 8. Here are some comments on these Exhibits:

1. Risk premiums, like interest rates and stock prices, are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched with current interest rates.
2. Exhibit 6 confirms the 1980–1984 section of Exhibit 3 in that it shows a strong inverse relationship between interest rates and risk premiums; we shall discuss shortly why this relationship holds.
3. Exhibit 7 shows that while risk premiums based on Value Line, Merrill Lynch, and Salomon Brothers

Exhibit 4. Estimated Monthly Risk Premiums for Electric Utilities Using Analysts' Growth Forecasts, January 1980–June 1984

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Jan 1980	6.21%	NA	NA	6.21%	10.18%
Feb 1980	5.77%	NA	NA	5.77%	10.86%
Mar 1980	4.73%	NA	NA	4.73%	12.59%
Apr 1980	5.02%	NA	NA	5.02%	12.71%
May 1980	4.73%	NA	NA	4.73%	11.04%
Jun 1980	5.09%	NA	NA	5.09%	10.37%
Jul 1980	5.41%	NA	NA	5.41%	9.86%
Aug 1980	5.72%	NA	NA	5.72%	10.29%
Sep 1980	5.16%	NA	NA	5.16%	11.41%
Oct 1980	5.62%	NA	NA	5.62%	11.75%
Nov 1980	5.09%	NA	NA	5.09%	12.33%
Dec 1980	5.65%	NA	NA	5.65%	12.37%
Annual Avg.	5.35%			5.35%	11.31%
Jan 1981	5.62%	4.76%	5.63%	5.34%	11.99%
Feb 1981	4.82%	4.87%	5.16%	4.95%	12.48%
Mar 1981	4.70%	3.73%	4.97%	4.47%	13.10%
Apr 1981	4.24%	3.23%	4.52%	4.00%	13.11%
May 1981	3.54%	3.24%	4.24%	3.67%	13.51%
Jun 1981	3.57%	4.04%	4.27%	3.96%	13.39%
Jul 1981	3.61%	3.63%	4.16%	3.80%	13.32%
Aug 1981	3.17%	3.05%	3.04%	3.09%	14.23%
Sep 1981	2.11%	2.24%	2.35%	2.23%	14.99%
Oct 1981	2.83%	2.64%	3.24%	2.90%	14.93%
Nov 1981	2.08%	2.49%	3.03%	2.53%	15.27%
Dec 1981	3.72%	3.45%	4.24%	3.80%	13.12%
Annual Avg.	3.67%	3.45%	4.07%	3.73%	13.62%
Jan 1982	3.70%	3.37%	4.04%	3.70%	14.00%
Feb 1982	3.05%	3.37%	3.70%	3.37%	14.37%
Mar 1982	3.15%	3.28%	3.75%	3.39%	13.96%
Apr 1982	3.49%	3.61%	4.29%	3.80%	13.69%
May 1982	3.08%	4.25%	3.91%	3.75%	13.47%
Jun 1982	3.16%	4.51%	4.72%	4.13%	13.53%
Jul 1982	2.57%	4.21%	4.21%	3.66%	14.48%
Aug 1982	4.33%	4.83%	5.27%	4.81%	13.69%
Sep 1982	4.08%	5.14%	5.58%	4.93%	12.40%
Oct 1982	5.35%	5.24%	6.34%	5.64%	11.95%
Nov 1982	5.67%	5.95%	6.91%	6.18%	10.97%
Dec 1982	6.31%	6.71%	7.45%	6.82%	10.52%
Annual Avg.	4.00%	4.54%	5.01%	4.52%	13.09%
Jan 1983	5.64%	6.04%	6.81%	6.16%	10.66%
Feb 1983	4.68%	5.99%	6.10%	5.59%	11.01%
Mar 1983	4.99%	6.89%	6.43%	6.10%	10.71%
Apr 1983	4.75%	5.82%	6.31%	5.63%	10.84%
May 1983	4.50%	6.41%	6.24%	5.72%	10.57%
Jun 1983	4.29%	5.21%	6.16%	5.22%	10.90%
Jul 1983	4.78%	5.72%	6.42%	5.64%	11.12%
Aug 1983	3.89%	4.74%	5.41%	4.68%	11.78%
Sep 1983	4.07%	4.90%	5.57%	4.85%	11.71%
Oct 1983	3.79%	4.64%	5.38%	4.60%	11.64%
Nov 1983	2.84%	3.77%	4.46%	3.69%	11.90%
Dec 1983	3.36%	4.27%	5.00%	4.21%	11.83%
Annual Avg.	4.30%	5.37%	5.86%	5.17%	11.22%
Jan 1984	4.06%	5.04%	5.65%	4.92%	11.97%
Feb 1984	4.25%	5.37%	5.96%	5.19%	11.76%
Mar 1984	4.73%	6.05%	6.38%	5.72%	12.12%
Apr 1984	4.78%	5.33%	6.32%	5.48%	12.51%
May 1984	4.36%	5.30%	6.42%	5.36%	12.78%
Jun 1984	3.54%	4.00%	5.63%	4.39%	13.60%

Exhibit 5. Monthly Risk Premiums Based on IBES Data

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Aug 1983	4.68%	4.10%	4.16%
Sep 1983	4.85%	4.43%	4.27%
Oct 1983	4.60%	4.31%	3.90%
Nov 1983	3.69%	3.36%	3.36%
Dec 1983	4.21%	3.86%	3.54%
Jan 1984	4.92%	4.68%	4.18%
Feb 1984	5.19%	5.00%	4.36%
Mar 1984	5.72%	5.35%	4.45%
Apr 1984	5.48%	5.33%	4.23%
May 1984	5.36%	5.26%	4.30%
Jun 1984	4.39%	4.47%	3.40%
Average Premiums	4.83%	4.56%	4.01%

Exhibit 6. Utility Risk Premiums and Interest Rates, 1980–1984

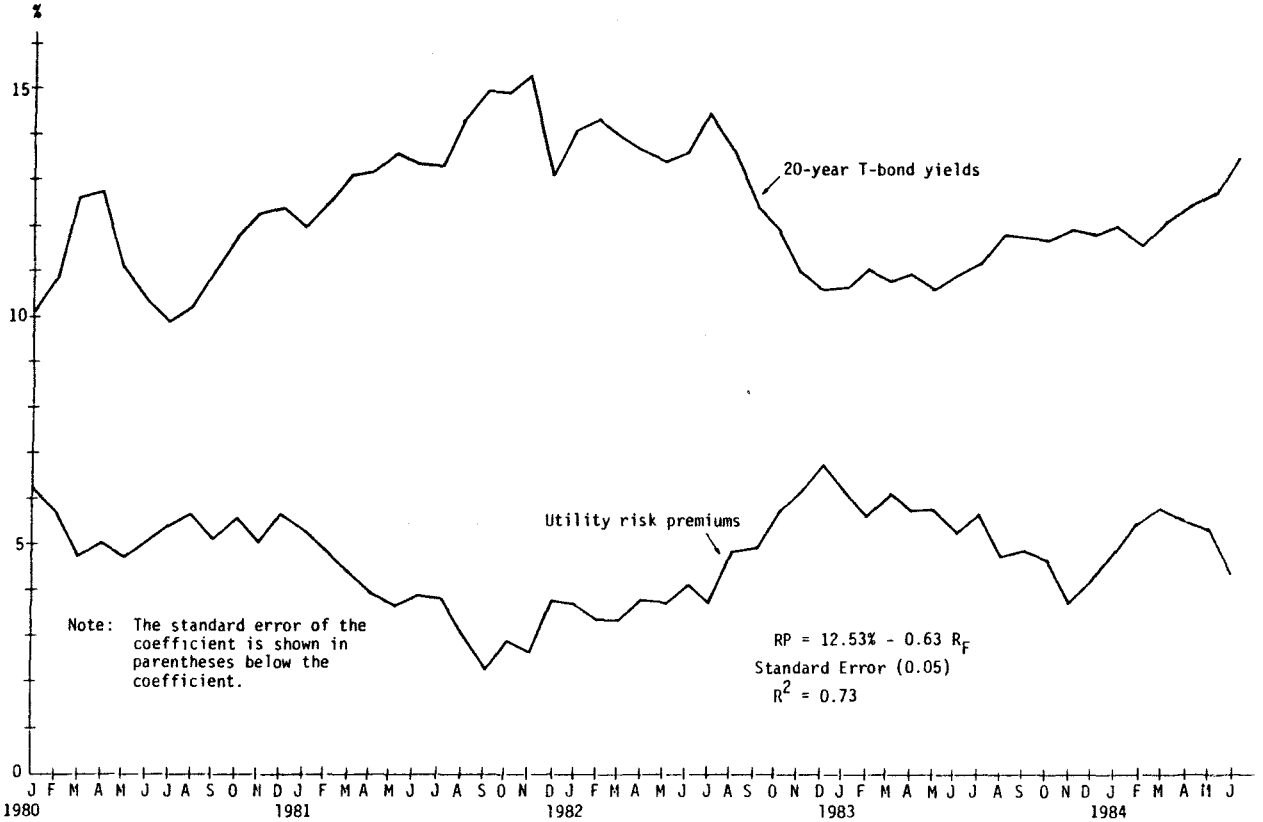


Exhibit 7. Monthly Risk Premiums, Electric Utilities, 1981–1984 (to Date)

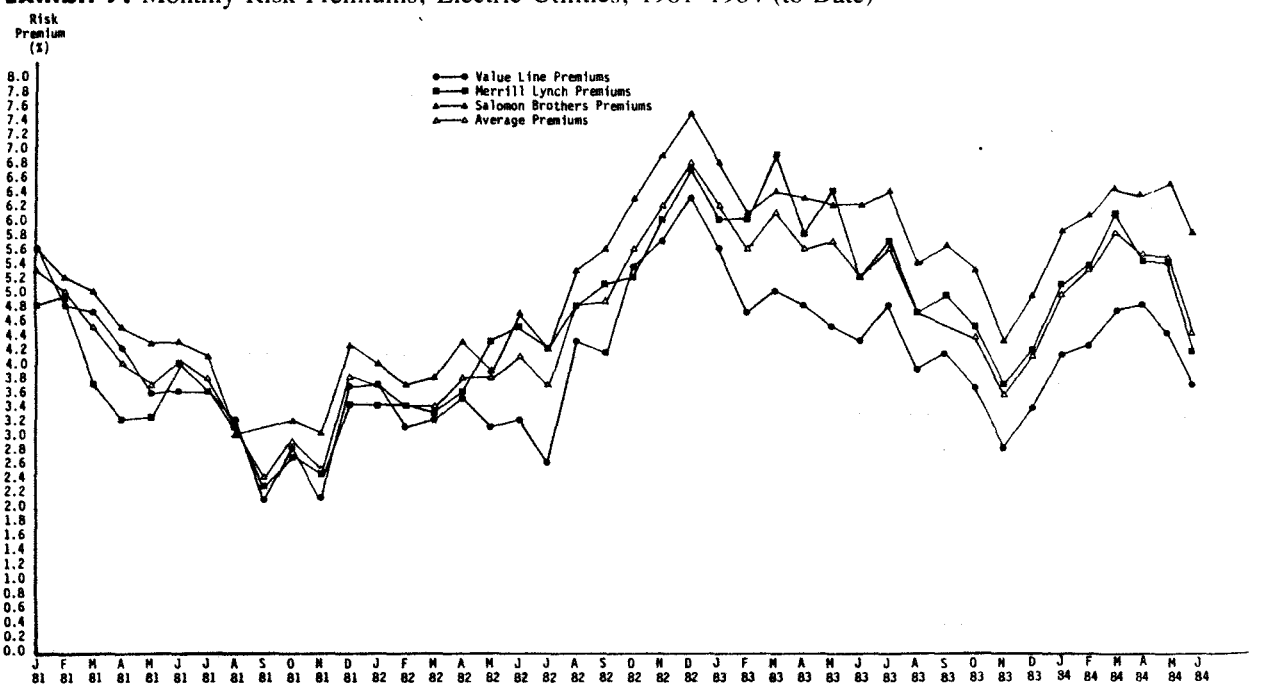
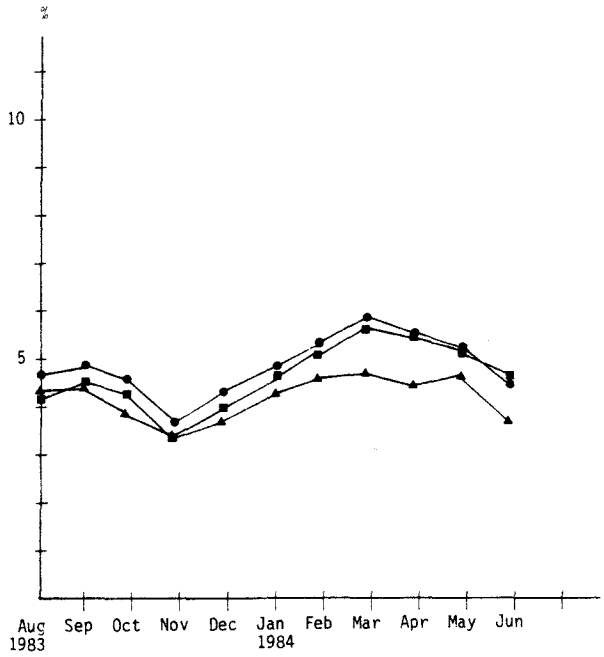


Exhibit 8. Comparative Risk Premium Data



do differ, the differences are not large given the nature of the estimates, and the premiums follow one another closely over time. Since all of the analysts are examining essentially the same data and since utility companies are not competitive with one another, and hence have relatively few secrets, the similarity among the analysts' forecasts is not surprising.

4. The IBES data, presented in Exhibit 5 and plotted in Exhibit 8, contain too few observations to enable us to draw strong conclusions, but (i) the Dow Jones Electrics risk premiums based on our three-analyst data have averaged 27 basis points above premiums based on the larger group of analysts surveyed by IBES and (ii) the premiums on the 11 Dow Jones Electrics have averaged 54 basis points higher than premiums for the entire utility industry followed by IBES. Given the variability in the data, we are, at this point, inclined to attribute these differences to random fluctuations, but as more data become available, it may turn out that the differences are statistically significant. In particular, the 11 electric utilities included in the Dow Jones Utility Index all have large nuclear investments, and this may cause them to be regarded as riskier than the industry average, which includes both nuclear and non-nuclear companies.

Tests of the Reasonableness of the Risk Premium Estimates

So far our claims to the reasonableness of our risk-premium estimates have been based on the reasonableness of our variable measures, particularly the measures of expected dividend growth rates. Essentially, we have argued that since there is strong evidence in the literature in support of analysts' forecasts, risk premiums based on these forecasts are reasonable. In the spirit of positive economics, however, it is also important to demonstrate the reasonableness of our results more directly.

It is theoretically possible to test for the validity of the risk-premium estimates in a CAPM framework. In a cross-sectional estimate of the CAPM equation,

$$(k - R_F)_i = \alpha_0 + \alpha_1\beta_i + u_i, \qquad (5)$$

we would expect

$$\hat{\alpha}_0 = 0 \text{ and } \hat{\alpha}_1 = k_M - R_F = \text{Market risk premium.}$$

This test, of course, would be a joint test of both the CAPM and the reasonableness of our risk-premium estimates. There is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities. Under these conditions, it is obvious that no unambiguous conclusion can be drawn regarding the efficacy of the premium estimates from such a test.[8]

A simpler and less ambiguous test is to show that the risk premiums are higher for lower rated firms than for higher rated firms. Using 1984 data, we classified the

[8]We carried out the test on a monthly basis for 1984 and found positive but statistically insignificant coefficients. A typical result (for April 1984) follows:

$$(k - R_F)_i = \underset{(0.91)}{3.1675} + \underset{(1.44)}{1.8031}\ \beta_i.$$

The figures in parentheses are standard errors. Utility risk premiums do increase with betas, but the intercept term is not zero as the CAPM would predict, and α_1 is both less than the predicted value and not statistically significant. Again, the observation that the coefficients do not conform to CAPM predictions could be as much a problem with CAPM specification for utilities as with the risk premium estimates.

A similar test was carried out by Friend, Westerfield, and Granito [9]. They tested the CAPM using expectational (survey) data rather than *ex post* holding period returns. They actually found their coefficient of β_i to be negative in all their cross-sectional tests.

Exhibit 9. Relationship between Risk Premiums and Bond Ratings, 1984*

Month	Aaa/AA	AA	Aa/A	A	A/BBB	BBB	Below BBB
January†	—	2.61%	3.06%	3.70%	5.07%	4.90%	9.45%
February	2.98%	3.17%	3.36%	4.03%	5.26%	5.14%	7.97%
March	2.34%	3.46%	3.29%	4.06%	5.43%	5.02%	8.28%
April	2.37%	3.03%	3.29%	3.88%	5.29%	4.97%	6.96%
May	2.00%	2.48%	3.42%	3.72%	4.72%	6.64%	8.81%
June	0.72%	2.17%	2.46%	3.16%	3.76%	5.00%	5.58%
Average	2.08%	2.82%	3.15%	3.76%	4.92%	5.28%	7.84%

*The risk premiums are based on IBES data for the electric utilities followed by both IBES and Salomon Brothers. The number of electric utilities followed by both firms varies from month to month. For the period between January and June 1984, the number of electrics followed by both firms ranged from 96 to 99 utilities.
†In January, there were no Aaa/AA companies. Subsequently, four utilities were upgraded to Aaa/AA.

utility industry into risk groups based on bond ratings. For each rating group, we estimated the average risk premium. The results, presented in Exhibit 9, clearly show that the lower the bond rating, the higher the risk premiums. Our premium estimates therefore would appear to pass this simple test of reasonableness.

Risk Premiums and Interest Rates

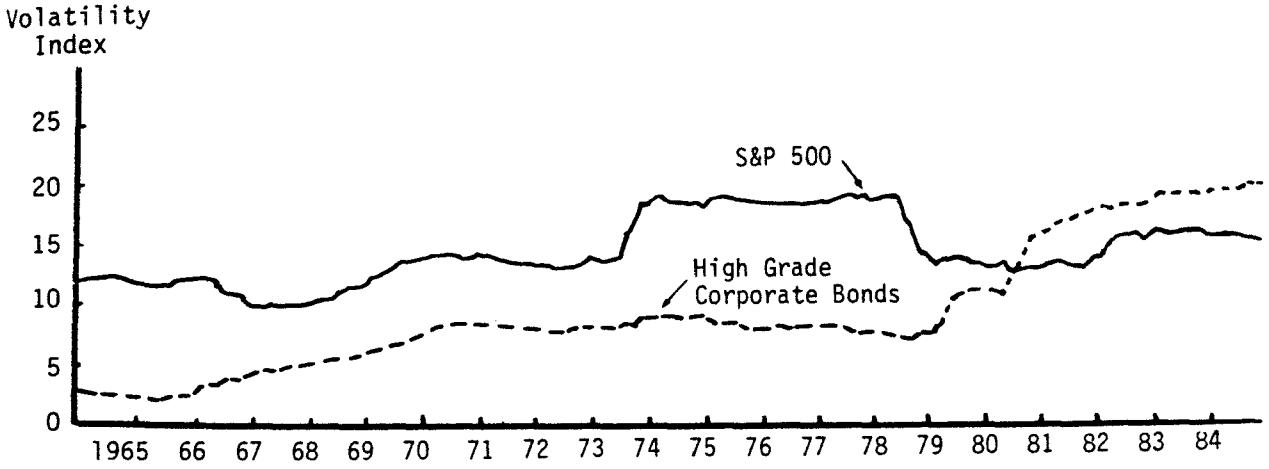
Traditionally, stocks have been regarded as being riskier than bonds because bondholders have a prior claim on earnings and assets. That is, stockholders stand at the end of the line and receive income and/or assets only after the claims of bondholders have been satisfied. However, if interest rates fluctuate, then the holders of long-term bonds can suffer losses (either realized or in an opportunity cost sense) even though they receive all contractually due payments. Therefore, if investors' worries about "interest rate risk" versus "earning power risk" vary over time, then perceived risk differentials between stocks and bonds, and hence risk premiums, will also vary.

Any number of events could occur to cause the perceived riskiness of stocks versus bonds to change, but probably the most pervasive factor, over the 1966–1984 period, is related to inflation. Inflationary expectations are, of course, reflected in interest rates. Therefore, one might expect to find a relationship between risk premiums and interest rates. As we noted in our discussion of Exhibit 3, risk premiums were positively correlated with interest rates from 1966 through 1979, but, beginning in 1980, the relationship turned negative. A possible explanation for this change is given next.

1966–1979 Period. During this period, inflation heated up, fuel prices soared, environmental problems surfaced, and demand for electricity slowed even as expensive new generating units were nearing completion. These cost increases required offsetting rate hikes to maintain profit levels. However, political pressure, combined with administrative procedures that were not designed to deal with a volatile economic environment, led to long periods of "regulatory lag" that caused utilities' earned ROEs to decline in absolute terms and to fall far below the cost of equity. These factors combined to cause utility stockholders to experience huge losses: S&P's Electric Index dropped from a mid-1960s high of 60.90 to a mid-1970s low of 20.41, a decrease of 66.5%. Industrial stocks also suffered losses during this period, but, on average, they were only one third as severe as the utilities' losses. Similarly, investors in long-term bonds had losses, but bond losses were less than half those of utility stocks. Note also that, during this period, (i) bond investors were able to reinvest coupons and maturity payments at rising rates, whereas the earned returns on equity did not rise, and (ii) utilities were providing a rising share of their operating income to debtholders versus stockholders (interest expense/book value of debt was rising, while net income/common equity was declining). This led to a widespread belief that utility commissions would provide enough revenues to keep utilities from going bankrupt (barring a disaster), and hence to protect the bondholders, but that they would not necessarily provide enough revenues either to permit the expected rate of dividend growth to occur or, perhaps, even to allow the dividend to be maintained.

Because of these experiences, investors came to regard inflation as having a more negative effect on utility stocks than on bonds. Therefore, when fears of inflation increased, utilities' measured risk premiums

Exhibit 10. Relative Volatility* of Stocks and Bonds, 1965–1984



*Volatility is measured as the standard deviation of total returns over the last 5 years.
Source: Merrill Lynch, *Quantitative Analysis*, May/June 1984.

also increased. A regression over the period 1966–1979, using our Exhibit 2 data, produced this result:

$$RP = 0.30\% + 0.73\ R_F; \qquad r^2 = 0.48.$$
$$(0.22)$$

This indicates that a one percentage point increase in the Treasury bond rate produced, on average, a 0.73 percentage point increase in the risk premium, and hence a 1.00 + 0.73 = 1.73 percentage point increase in the cost of equity for utilities.

1980–1984 Period. The situation changed dramatically in 1980 and thereafter. Except for a few companies with nuclear construction problems, the utilities' financial situations stabilized in the early 1980s, and then improved significantly from 1982 to 1984. Both the companies and their regulators were learning to live with inflation; many construction programs were completed; regulatory lags were shortened; and in general the situation was much better for utility equity investors. In the meantime, over most of the 1980–1984 period, interest rates and bond prices fluctuated violently, both in an absolute sense and relative to common stocks. Exhibit 10 shows the volatility of corporate bonds very clearly. Over most of the eighteen-year period, stock returns were much more volatile than returns on bonds. However, that situation changed in October 1979, when the Fed began to focus on the money supply rather than on interest rates.[9]

In the 1980–1984 period, an increase in inflationary expectations has had a more adverse effect on bonds than on utility stocks. If the expected rate of inflation increases, then interest rates *will increase* and bond prices *will fall*. Thus, uncertainty about inflation translates directly into risk in the bond markets. The effect of inflation on stocks, including utility stocks, is less clear. If inflation increases, then utilities should, in theory, be able to obtain rate increases that would offset increases in operating costs and also compensate for the higher cost of equity. Thus, with "proper" regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds. This hedge did not work at all well during the 1966–1979 period, because inflation-induced increases in operating and capital costs were not offset by timely rate increases. However, as noted earlier, both the utilities and their regulators seem to have learned to live better with inflation during the 1980s.

Since inflation is today regarded as a major investment risk, and since utility stocks now seem to provide a better hedge against unanticipated inflation than do

[9]Because the standard deviations in Exhibit 10 are based on the last five years of data, even if bond returns stabilize, as they did beginning in 1982, their reported volatility will remain high for several more years. Thus, Exhibit 10 gives a rough indication of the current relative riskiness of stocks versus bonds, but the measure is by no means precise or necessarily indicative of future expectations.

bonds, the interest-rate risk inherent in bonds offsets, to a greater extent than was true earlier, the higher operating risk that is inherent in equities. Therefore, when inflationary fears rise, the perceived riskiness of bonds rises, helping to push up interest rates. However, since investors are today less concerned about inflation's impact on utility stocks than on bonds, the utilities' cost of equity does not rise as much as that of debt, so the observed risk premium tends to fall.

For the 1980–1984 period, we found the following relationship (see Exhibit 6):

$$RP = 12.53\% - 0.63\ R_F; \qquad r^2 = 0.73.$$
$$(0.05)$$

Thus, a one percentage point increase in the T-bond rate, on average, caused the risk premium to fall by 0.63%, and hence it led to a 1.00 − 0.63 = 0.37 percentage point increase in the cost of equity to an average utility. This contrasts sharply with the pre-1980 period, when a one percentage point increase in interest rates led, on average, to a 1.73 percentage point increase in the cost of equity.

Summary and Implications

We began by reviewing a number of earlier studies. From them, we concluded that, for cost of capital estimation purposes, risk premiums must be based on expectations, not on past realized holding period returns. Next, we noted that expectational risk premiums may be estimated either from surveys, such as the ones Charles Benore has conducted, or by use of DCF techniques. Further, we found that, although growth rates for use in the DCF model can be either developed from time-series data or obtained from security analysts, analysts' growth forecasts are more reflective of investors' views, and, hence, in our opinion are preferable for use in risk-premium studies.

Using analysts' growth rates and the DCF model, we estimated risk premiums over several different periods. From 1966 to 1984, risk premiums for both electric utilities and industrial stocks varied widely from year to year. Also, during the first half of the period, the utilities had smaller risk premiums than the industrials, but after the mid-1970s, the risk premiums for the two groups were, on average, about equal.

The effects of changing interest rates on risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 1980 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premiums shifted from positive to negative. Earlier, a 1.00 percentage point increase in interest rates had led, on average, to a 1.73% increase in the utilities' cost of equity, but after 1980 a 1.00 percentage point increase in the cost of debt was associated with an increase of only 0.37% in the cost of equity.

Our study also has implications for the use of the CAPM to estimate the cost of equity for utilities. The CAPM studies that we have seen typically use either Ibbotson-Sinquefield or similar historic holding period returns as the basis for estimating the market risk premium. Such usage implicitly assumes (i) that *ex post* returns data can be used to proxy *ex ante* expectations and (ii) that the market risk premium is relatively stable over time. Our analysis suggests that neither of these assumptions is correct; at least for utility stocks, *ex post* returns data do not appear to be reflective of *ex ante* expectations, and risk premiums are volatile, not stable.

Unstable risk premiums also make us question the FERC and FCC proposals to estimate a risk premium for the utilities every two years and then to add this premium to a current Treasury bond rate to determine a utility's cost of equity. Administratively, this proposal would be easy to handle, but risk premiums are simply too volatile to be left in place for two years.

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"Unusual and Exigent" Conditions Elicit Aggressive Policy Actions

- **Aggressive monetary policy actions involve Fed's balance sheet, not interest rates**
- **Fiscal policy actions make deficit four times the size forecast just two months ago**
- **Even as rates start to increase, they do so very slowly**
- **Long-term outlook just sees modest 2% growth and modest rise in interest rates**

In a 1935 amendment to the Federal Reserve Act of 1913, the Fed was enabled to extend credit to certain parties during "unusual and exigent circumstances." The current period is certainly "unusual." It is also "exigent," meaning, according to Merriam-Webster, that conditions "require immediate aid or action" and that they "require or call for much." In particular, the Fed's usual policy tool, the federal funds rate, was already cut to just above zero by mid-March, so the Federal Open Market Committee can't try to support the economy by lowering that unless they want to reconsider the view against negative interest rates.

Clearly, some policy action was needed. GDP dropped at a 5% annual rate in Q1 and is estimated by the Blue Chip panel to plunge at a 34.0% rate this quarter. A turnaround toward a 15% rate of growth is expected in Q3.

Fed balance sheet already up by $2.94 trillion. So in response to this perceived need for creative policy actions, the Fed has established nine credit-granting facilities reaching out to, as the descriptions all say, "households and businesses." And, as well, to state and local governments. In each case, the Fed is not the actual lender to the actual user of the funds, but it supports, among others, financial institution lenders such as commercial paper issuers (CPFF), money market mutual funds (MMLF) and the well-known Paycheck Protection Program Liquidity Facility (PPPLF) for small businesses. These programs began in late March and most recently have totaled some $130 billion. Since mid-March, the Fed has also bought $1.6 trillion in U.S. Government securities and its total assets have grown from $4.16 trillion to $7.10 trillion.

While the special programs cover just a fraction of the increase in the Fed's assets and a fraction of their legislated totals, they have carried larger announcement effects than the actual dollar amounts might imply. Fed Vice Chair Richard Clarida commented on this in a speech May 21; "just the announcement that these backstop facilities would soon be launched appears to have bolstered confidence in capital markets, allowing many companies to finance themselves privately even before the facilities were up and running."

Fed needs to pair with fiscal policy to give economy effective help. One other clarification on the role of legislation in these Federal Reserve actions. Vice Chair Clarida made a helpful point: ". . . it is important to note that the Fed's statutory authority grants us *lending* powers, not *spending* powers. The Fed is not authorized to grant money to particular beneficiaries, to meet the payroll expenses of small businesses, or to underwrite the unemployment benefits of displaced workers. Programs to support such worthy goals reside squarely in the domain of fiscal policy. The Fed can only make loans to solvent entities with the expectation the loans will be paid back. Direct fiscal support for the economy is thus also essential to sustain economic activity and complement what monetary policy cannot accomplish on its own."

The Blue Chip Financial Forecasts panel believes the Fed's total assets will reach $9.4 trillion at the end of this year, so it would acquire another $2.3 trillion in securities and special facilities loans. At the end of 2021, the panel estimates a balance sheet of $10.2 trillion, with a few of the panelists actually looking for reductions in the Fed's total assets.

Aggressive fiscal policy as well. Fiscal policy actions include the coordination with the Federal Reserve funded programs as well as some other CARES Act benefits, special exemptions on the SNAP food stamps program, more funding for COVID-19 testing, increased funding for certain small business grants and so on. Before all this was enacted during March and April, the March 1st issue of Blue Chip Financial Forecasts included a Special Question asking for panelists' budget deficit estimate for fiscal 2020. They said then that after the $984 billion in fiscal 2019, the fiscal 2020 deficit would be $1.077 trillion. Now the panel is saying $4.0 trillion this fiscal year and $2.5 trillion in fiscal 2021.

As to the more standard interest rate forecasts, the panel expects that the Fed would hold the federal funds rate at its current almost-zero level until the middle of next year, when it would start to raise rates. Even then, the increase in Q3 2021 would still be quite modest, with just a dozen members of the Blue Chip panel seeing the rate higher than it has been recently and most of those by only a token amount. Other interest rates would rise somewhat more over the forecast span to Q3 2021, with ten-year Treasuries moving from their recent yield of 66 basis points to 1.2% by Q3 2021. Thus, the yield curve would steepen somewhat.

Long-term forecasts see growth, inflation and funds rate centering on 2%. This month's Financial Forecasts survey includes the semi-annual look at long-term trends in rates. GDP growth starts this coming decade slightly stronger at 3.2% in 2021 and 2022, and then moderates to 2.0% by 2026. Over the following five years it would average 2.1% a year. Inflation, measured by the CPI, would be 0.2% across this year, Q4 over Q4, then climb to 1.3% next year and 2.1% across the next five years and 2.2% the five years after that.

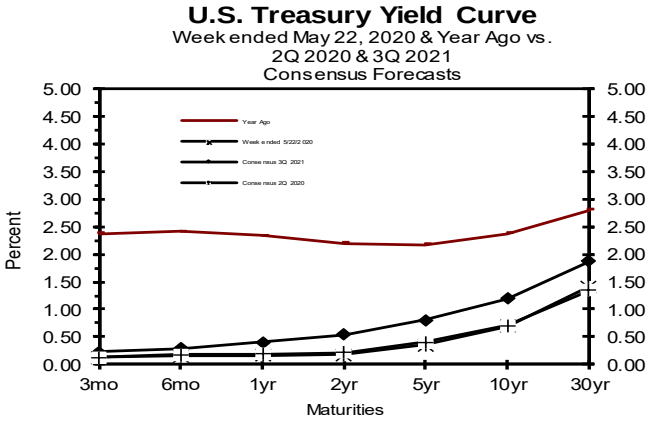
The fed funds rate would climb gradually toward 2%, reaching that between 2025 and 2026, and then hover just above that level during the following five years. Ten-year Treasury yields would increase from an average of 0.93% this year toward 1.2% next year, with averages of 2.3% and 3.1% during the two succeeding five-year periods. The pattern traced by these projections suggests that the aftermath of the current exigent economic conditions might take at least a couple of years to settle out and only further into the 2020s decade would the economy settle into a more orderly and sustainable situation.

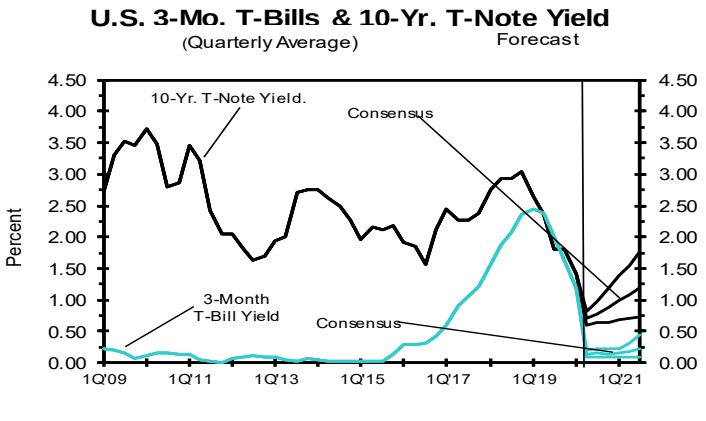
Carol Stone, CBE (Haver Analytics, New York, NY)

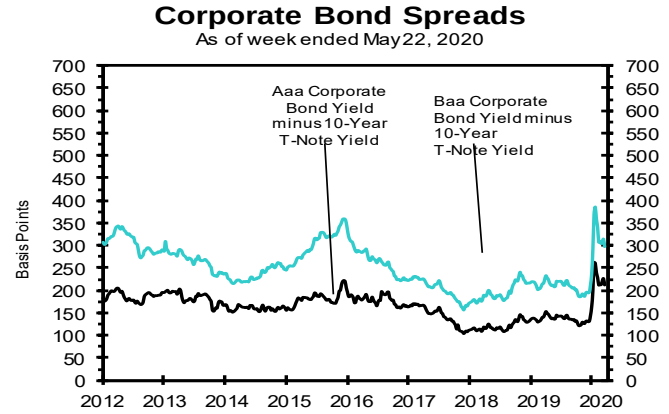
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

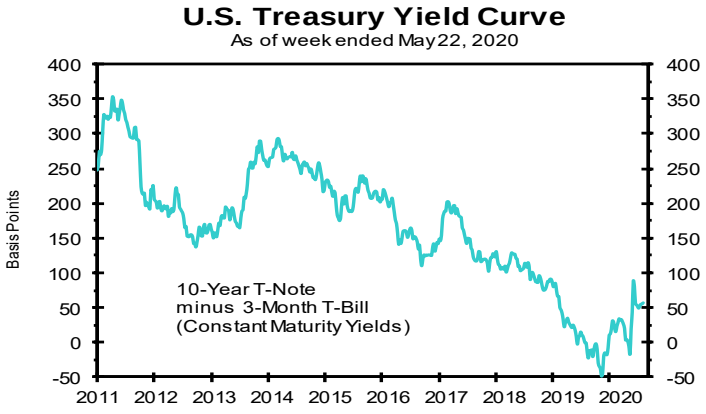
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 22	May 15	May 8	May 1	Apr	Mar	Feb	1Q 2020	2020	2020	2020	2021	2021	2021
Federal Funds Rate	0.05	0.05	0.05	0.04	0.05	0.65	1.58	1.26	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.78	4.75	4.43	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**
LIBOR, 3-mo.	0.37	0.40	0.46	0.68	1.09	1.10	1.68	1.53	**0.7**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**
Commercial Paper, 1-mo.	0.14	0.12	0.14	0.19	0.47	1.36	1.55	1.49	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**
Treasury bill, 3-mo.	0.12	0.12	0.12	0.11	0.14	0.30	1.54	1.13	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Treasury bill, 6-mo.	0.15	0.15	0.15	0.13	0.17	0.30	1.51	1.12	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**
Treasury bill, 1 yr.	0.16	0.15	0.16	0.17	0.18	0.33	1.41	1.09	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Treasury note, 2 yr.	0.17	0.16	0.17	0.21	0.22	0.45	1.33	1.10	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**
Treasury note, 5 yr.	0.35	0.33	0.34	0.37	0.39	0.59	1.32	1.16	**0.4**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**
Treasury note, 10 yr.	0.69	0.67	0.67	0.64	0.66	0.87	1.50	1.38	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**
Treasury note, 30 yr.	1.41	1.36	1.34	1.25	1.27	1.46	1.97	1.88	**1.4**	**1.5**	**1.5**	**1.7**	**1.8**	**1.9**
Corporate Aaa bond	2.82	2.94	2.89	2.77	2.86	3.11	2.85	3.00	**2.5**	**2.6**	**2.7**	**2.7**	**2.8**	**2.9**
Corporate Baa bond	3.66	3.81	3.74	3.68	3.87	4.11	3.50	3.76	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.3**
State & Local bonds	3.26	3.37	3.46	3.50	3.41	3.29	2.93	3.07	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**
Home mortgage rate	3.24	3.28	3.26	3.23	3.31	3.45	3.47	3.51	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2018	2018	2018	2019	2019	2019	2019	2020	2020	2020	2020	2021	2021	2021
Fed's AFE $ Index	105.5	107.8	109.4	109.4	110.3	110.5	110.3	111.2	**113.2**	**113.6**	**113.6**	**113.4**	**112.9**	**112.4**
Real GDP	3.5	2.9	1.1	3.1	2.0	2.1	2.1	-5.0	**-34.0**	**15.2**	**8.2**	**6.2**	**4.7**	**3.7**
GDP Price Index	3.2	2.0	1.6	1.1	2.4	1.8	1.3	1.4	**-0.4**	**1.0**	**1.3**	**1.5**	**1.7**	**1.7**
Consumer Price Index	2.2	2.1	1.3	0.9	3.0	1.8	2.4	1.2	**-3.2**	**1.3**	**1.7**	**2.1**	**1.9**	**1.9**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).









----------Policy Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.13	0.13	2.38	**0.12**	**0.12**	**0.13**
Japan	-0.10	-0.10	-0.10	**-0.09**	**-0.09**	**-0.09**
U.K.	0.10	0.10	0.75	**0.10**	**0.09**	**0.09**
Switzerland	-0.75	-0.75	-0.75	**-0.75**	**-0.75**	**-0.75**
Canada	0.25	0.25	1.75	**0.23**	**0.25**	**0.25**
Australia	0.25	0.25	1.50	**0.25**	**0.25**	**0.29**
Euro area	0.00	0.00	0.00	**0.00**	**0.00**	**0.00**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.66	0.60	2.32	**0.73**	**0.78**	**0.92**
Germany	-0.49	-0.47	-0.12	**-0.45**	**-0.39**	**-0.29**
Japan	0.00	-0.02	-0.07	**-0.05**	**-0.07**	**-0.07**
U.K.	0.21	0.32	1.03	**0.31**	**0.39**	**0.55**
France	-0.04	0.03	0.28	**-0.05**	**-0.04**	**0.04**
Italy	1.62	1.84	2.55	**1.72**	**1.63**	**1.61**
Switzerland	-0.51	-0.43	-0.38	**-0.58**	**-0.53**	**-0.49**
Canada	0.51	0.58	1.61	**0.70**	**0.75**	**0.96**
Australia	0.87	0.88	1.52	**0.91**	**0.87**	**0.91**
Spain	0.68	1.01	0.83	**0.72**	**0.73**	**0.74**

----------Foreign Exchange Rates[3]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	113.50	114.04	110.72	**114.4**	**114.5**	**112.6**
Japan	107.50	107.44	109.38	**107.6**	**108.2**	**109.1**
U.K.	1.22	1.23	1.27	**1.22**	**1.23**	**1.26**
Switzerland	0.97	0.98	1.00	**0.97**	**0.96**	**0.96**
Canada	1.40	1.41	1.35	**1.41**	**1.40**	**1.37**
Australia	0.65	0.64	0.69	**0.64**	**0.64**	**0.66**
Euro	1.09	1.08	1.12	**1.09**	**1.10**	**1.12**

	Consensus Policy Rates vs. US Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-0.23	**-0.22**	Germany	-1.15	**-1.21**
U.K.	-0.03	**-0.03**	Japan	-0.66	**-0.98**
Switzerland	-0.88	**-0.88**	U.K.	-0.45	**-0.37**
Canada	0.13	**0.13**	France	-0.70	**-0.88**
Australia	0.13	**0.16**	Italy	0.96	**0.69**
Euro area	-0.13	**-0.13**	Switzerland	-1.17	**-1.40**
			Canada	-0.15	**0.04**
			Australia	0.21	**-0.01**
			Spain	0.02	**-0.18**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International Since the middle of March when the coronavirus outbreak turned into a pandemic and large parts of economies were shut down, the Fed has increased its balance sheet by nearly $2.8 trillion, or 65%, to just over $7 trillion. Other major central banks have followed the Fed's aggressive lead. The European Central Bank has also restarted its asset purchase program and created a new one specially to confront the pandemic—the Pandemic Emergency Purchase Program (PEPP), which is scheduled to purchase €750 billion of assets by the end of this year. Since PEPP purchases were initiated at the beginning of April, the ECB has bought €212 billion of securities and has purchased another €107 billion in its APP (restarted in mid-March), increasing the ECB's assets by 18% to 46% of 2020 Q1 euro area GDP. Analysts generally expect the ECB to increase and to extend the PEPP at its June 4 Council meeting.

In mid-March, the Bank of England's Monetary Policy Committee voted unanimously to increase the Bank's holdings of UK government bonds and sterling non-financial investment-grade corporate bonds by £200 billion to a total of £645 billion. Since then, it has purchased nearly £126 billion of new securities. The Bank of England's external forecasters expect the Bank's total holdings to be increased to nearly £700 billion by the second quarter of 2021. The Bank of Japan has also increased its ongoing asset purchase program and created several new lending facilities. The most recent one aimed at increasing credit flow to small and medium-sized business was announced after an emergency meeting on May 22. Since the middle of March, the BoJ's assets have risen ¥43 trillion to 116% of Q1 nominal GDP.

Two central banks that had eschewed quantitative easing during the global financial crisis, the Reserve Bank of Australia and the Bank of Canada, have recently started asset purchase programs and have been quite aggressive. The RBA's program is similar to the Bank of Japan's yield curve control. The RBA intends to buy sufficient government and semi-government bonds to stabilize the yield on the 3-year government bond at 0.25%. Since mid-March, the Bank has increased its assets by 44%, buying A$111 billion of securities. Over this period the 3-year government bond yield has averaged 0.26% versus 0.64% during the first 2-1/2 months of 2020.

At the beginning of April, the Bank of Canada embarked on an asset purchasing campaign in which it intends to buy C$5 billion of Canadian government securities per week "until the economic recovery is well under way." So far, the Bank has purchased nearly C$50 billion of government bonds though its overall balance sheet has increased by much more—C$288 billion, a 187% increase—as repos and purchases of other securities have soared.

As the economic costs of the lockdowns escalate by unprecedented magnitudes, monetary policymakers have appealed for more fiscal support. The US government has legislated more than $2.7 trillion in aid and programs aimed at reducing the economic hit from the pandemic and the House has passed another $3 trillion package. Led by the fiscal authorities in Germany and France, individual euro area governments have also enacted aid programs totaling billions of euros. However, the most significant euro area fiscal policy response would be the €1.85 trillion coronavirus response plan recently proposed by the European Union. The proposal is composed of a €750 billion immediate recovery plan and an additional €1.1 trillion of economic activity-boosting budget over the next seven years. The proposal's largest hurdle is that it must be accepted by all 27 EU members, which at the very least would take some time. But if that can be accomplished, this would be a major step toward increased fiscal union across the bloc. Japan's fiscal policymakers have recently taken a more concrete step. In late May the Cabinet approved a second supplemental budget, which should be legislated sometime in June. This supplemental budget is estimated at slightly more than 6% of GDP on top the 5% of GDP supplemental budget passed in late April. Nearly half of the new supplement is earmarked for support to business.

Second Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.9	na	na	na	na	0.5 H	0.6 H	0.9	1.6	na	na	na	na	na	-40.0	-2.0	-3.9
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.3	0.5	0.8	1.3	na	na	na	na	na	-39.0	1.7	-2.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.3	na	na	na	3.3	na	-27.7	na	-4.1
Via Nova Investment Mgt.	0.2	3.3 H	0.8	0.2	0.1	0.1	0.1	0.2	0.4	0.7	1.3	2.9	4.2	1.6	3.2	112.8	-20.0	-1.0	-4.0
ACIMA Private Wealth	0.1	3.3 H	1.0	1.4	0.1	0.2	0.2	0.2	0.3	0.7	1.4	2.5	4.2	2.4	3.7 H	113.0	-40.0	1.3	1.5
Action Economics	0.1	3.3 H	1.5 H	0.2	0.1	0.1	0.1	0.2	0.4	0.7	1.4	2.4	3.8	2.7	3.5	111.3	-38.0	-2.8	-3.9
Amherst Pierpont Securities	0.1	3.3 H	0.6	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.5	4.1	2.5	3.3	113.5	-32.0	1.5	-3.2
Bank of America	0.1	na	0.6	na	na	na	na	0.2	0.3	0.5 L	1.0 L	na	na	na	na	na	-40.0	-1.0	-3.2
Barclays	0.1	3.3 H	na	na	na	na	na	0.2	0.5	0.7	1.4	na	na	na	na	na	-40.0	-2.7	-3.9
BMO Capital Markets	0.1	3.3 H	0.7	na	0.1	0.2	0.2	0.2	0.4	0.7	1.3	na	na	na	3.2	114.3 H	-40.0	-2.0	-3.9
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.3	na	0.8	na	na	na	na	na	na	-40.0	na	-4.1
Chan Economics	0.1	3.3 H	0.8	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.5	-35.0	1.9	2.0 H
Chmura Economics & Analytics	0.1	3.3 H	0.7	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	na	na	3.3	na	-18.4	1.0	1.2
Comerica Bank	0.1	3.2	0.7	na	0.1	0.2	0.2	0.2	0.4	0.7	1.3	na	na	na	3.1	na	-28.3	-0.1	-4.4
Daiwa Capital Markets America	0.1	3.3 H	0.9	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.6	4.1	na	3.3	114.0	-38.4	0.5	-3.2
DePrince & Assoc.	0.1	3.3 H	0.6	0.3	0.1	0.2	0.2	0.2	0.3	0.7	1.3	2.6	4.1	2.5	3.2	113.2	-17.6 H	-1.7	-1.8
Fannie Mae	0.1	3.3 H	na	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	na	na	na	3.3	na	-36.6	-0.9	-3.3
Georgia State University	0.1	3.3 H	na	na	0.0 L	0.0 L	0.0 L	0.1	0.4	0.7	1.3	2.9	4.5	na	3.4	na	-41.8	-1.0	-3.3
GLC Financial Economics	0.1	3.3 H	0.5	0.2	0.1	0.1	0.2	0.2	0.4	0.6	1.3	2.8	4.0	2.8	3.4	109.4 L	-32.7	0.0	-1.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	0.2	0.3	0.6	1.1	na	na	na	3.2	na	-39.0	-0.2	-4.9
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3 L	0.3	0.2	0.2	0.2	0.2	0.4	0.7	1.3	2.0	4.4	na	3.3	na	-35.7	-1.0	-3.2
Loomis, Sayles & Company	0.1	3.3 H	0.6	0.2	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.6	3.8	3.3	3.3	113.1	-40.0	-1.1	-4.0
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.4	0.1 L	0.1	0.2	0.2	0.2	0.4	0.6	1.4	2.7	3.7	2.8	3.3	113.8	-35.5	1.0	-3.3
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.6	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.1 L	1.0	0.3	0.4 H	0.4 H	0.4 H	0.4	0.5	0.6	1.5	2.5	4.2	2.6	3.2	na	-32.7	2.1 H	-3.9
Moody's Capital Markets Group	0.1	3.3 H	0.6	0.3	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	4.0	3.0	3.3	114.0	-33.5	-0.5	-4.3
MUFG Union Bank	0.1	3.3 H	0.6	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.4	3.9	2.8	3.3	113.5	-30.0	1.5	-3.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6 H	0.1	0.1	0.2	0.2	0.4	0.7	1.2	2.1	4.1	2.3	3.3	114.0	-22.0	0.8	-1.2
NatWest Markets	0.1	3.3 H	0.7	0.4	0.2	0.2	0.2	0.2	0.4	0.7	1.5	2.8	3.6	3.5 H	3.2	113.5	-35.6	-2.0	-4.0
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.3	0.4	0.6	na	na	na	na	na	na	-49.2 L	1.7	-3.5
Oxford Economics	0.1	3.3 H	1.1	na	0.1	0.2	0.2	0.3	0.4	0.6	1.5	1.6 L	na	na	3.3	114.3 H	-36.6	-3.9 L	-6.5 L
PNC Financial Services Corp.	0.1	3.3 H	0.6	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	na	4.1	0.7 L	3.3	na	-30.1	-0.3	-5.8
RDQ Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.2	0.2	0.2	0.5	0.7	1.3	2.4	3.7	3.1	3.4	113.2	-34.7	1.0	-3.5
Regions Financial Corporation	0.1	3.3 H	0.6	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.7	4.2	2.6	3.4	113.6	-36.2	1.9	-4.7
S&P Global	0.1	3.3 H	1.0	na	0.0 L	0.0 L	0.0 L	0.0 L	0.4	0.7	1.4	na	na	na	3.3	na	-34.6	-2.1	-1.4
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.2	0.4	0.7	1.4	na	na	na	na	na	-30.0	0.8	-3.5
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6 H	1.0 H	1.7 H	3.4 H	5.4 H	na	2.7 L	na	-39.5	na	-4.0
The Northern Trust Company	0.1	3.2	0.6	0.2	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	3.6	3.4	3.3	113.5	-36.5	-2.1	-3.0
TS Lombard	0.1	3.2	0.4	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.4	2.1	3.1 L	1.3	2.7 L	113.3	-23.0	-3.0	-5.0
Wells Fargo	0.1	3.3 H	0.3 L	0.1 L	0.1	0.2	0.2	0.2	0.4	0.8	1.4	2.0	3.7	1.9	3.3	na	-24.7	-1.3	-4.0
ING	0.0 L	na	0.4	na	na	na	na	0.0 L	0.2 L	1.0 H	1.0 L	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.7**	**0.3**	**0.1**	**0.2**	**0.2**	**0.2**	**0.4**	**0.7**	**1.4**	**2.5**	**4.0**	**2.5**	**3.3**	**113.2**	**-34.0**	**-0.4**	**-3.2**
Top 10 Avg.	0.2	3.3	1.0	0.6	0.2	0.2	0.2	0.3	0.5	0.8	1.5	2.8	4.4	3.0	3.4	113.9	-24.2	1.6	-0.9
Bottom 10 Avg.	0.1	3.3	0.4	0.2	0.1	0.1	0.1	0.2	0.3	0.6	1.2	2.2	3.7	2.0	3.1	112.6	-41.1	-2.4	-4.8
May Consensus	0.1	3.3	0.9	0.4	0.1	0.1	0.2	0.2	0.4	0.7	1.3	2.6	4.3	2.6	3.3	113.5	-27.8	0.1	-2.4
Number of Forecasts Changed From A Month Ago:																			
Down	3	2	16	11	5	3	5	14	8	6	2	9	10	6	11	9	25	20	19
Same	36	27	9	6	23	22	21	22	25	25	19	8	6	7	14	6	10	12	9
Up	2	4	4	5	6	7	5	4	6	10	17	8	8	7	7	4	4	4	11
Diffusion Index	49%	53%	29%	36%	51%	56%	50%	38%	47%	55%	70%	48%	46%	53%	44%	37%	23%	28%	40%

Third Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.2	0.4	0.7	1.5	na	na	na	na	na	23.0	1.8	2.0
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.4 H	0.6 H	0.9	1.5	na	na	na	na	na	25.9	-0.2	-1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.8	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	114.0	5.0	0.0	-1.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.1	0.2 H	0.2	0.2	0.3 L	0.6	1.3	na	na	na	3.3	na	13.8	na	0.4
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.5	0.1	0.1	0.1	0.2	0.4	0.8	1.5	2.8	4.7	2.6	4.0 H	114.0	18.0	1.1	-5.0 L
Action Economics	0.1	3.3 H	0.5	0.2	0.1	0.2 H	0.2	0.4 H	0.6 H	0.9	1.6	2.3	3.5	3.0	3.6	113.6	28.0	1.7	1.2
Amherst Pierpont Securities	0.1	3.3 H	0.4	0.1 L	0.2	0.2 H	0.3	0.4 H	0.6 H	1.0	1.7 H	2.8	4.3	2.8	3.6	114.0	28.0	2.0	3.5
Bank of America	0.1	na	0.5	na	na	na	na	0.3	0.4	0.6	1.2	na	na	na	na	na	7.0	1.6	2.9
Barclays	0.1	3.3 H	na	na	na	na	na	0.2	0.5	0.8	1.5	na	na	na	na	na	25.0	2.0	2.5
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2 H	0.2	0.3	0.5	0.8	1.5	na	na	na	3.0	115.1 H	43.0 H	1.4	2.1
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.4 H	na	1.0	na	na	na	na	na	na	22.2	na	1.2
Chan Economics	0.1	3.3 H	0.7	0.4	0.1	0.2 H	0.2	0.2	0.3 L	0.6	1.3	2.6	4.6	2.6	3.3	113.7	6.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.6	0.1 L	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.6	na	na	3.3	na	1.0	1.2	1.2
Comerica Bank	0.1	3.2 L	0.5	na	0.1	0.2 H	0.2	0.2	0.5	0.7	1.5	na	na	na	3.1	na	12.1	1.0	2.1
Daiwa Capital Markets America	0.1	3.3 H	0.6	0.2	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.5	4.1	na	3.3	114.0	8.5	1.0	1.5
DePrince & Assoc.	0.1	3.3 H	0.3 L	0.3	0.1	0.1	0.1	0.2	0.3 L	0.7	1.4	2.9	4.0	2.6	3.1	112.6	2.5	0.6	0.7
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2 H	0.2	0.2	0.4	0.7	1.5	na	na	na	3.2	na	18.4	1.3	1.6
Georgia State University	0.1	3.3 H	na	na	0.0 L	-0.1 L	0.0 L	0.1 L	0.4	0.7	1.4	3.3	4.6	na	3.5	na	3.4	1.6	2.3
GLC Financial Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	3.0	4.2	3.0	3.6	110.1 L	-18.9 L	0.9	1.1
Goldman Sachs & Co.	0.1	na	na	na	0.5 H	na	na	0.2	0.4	0.5 L	1.0 L	na	na	na	2.8	na	29.0	2.7 H	1.4
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3 L	0.3	0.2	0.2 H	0.3	0.4 H	0.5	0.7	1.4	2.1	2.6 L	na	3.3	na	7.6	2.4	3.0
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.2 H	0.2	0.2	0.3 L	0.7	1.4	2.6	3.7	2.9	3.2	113.1	9.3	1.4	2.0
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.4	0.2	0.2	0.2 H	0.3	0.3	0.4	0.7	1.4	2.7	3.9	3.0	3.4	114.0	-1.0	1.2	2.5
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.7	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.9	0.1 L	0.2	0.2 H	0.4 H	0.4 H	0.5	0.6	1.7 H	2.8	4.3	2.6	3.1	na	16.2	-2.1 L	1.4
Moody's Capital Markets Group	0.1	3.3 H	0.5	0.2	0.1	0.2 H	0.2	0.2	0.4	0.7	1.3	2.5	4.0	3.0	3.3	114.6	15.7	0.9	1.3
MUFG Union Bank	0.1	3.3 H	0.3 L	na	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.8	3.2	114.0	15.0	1.5	2.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6 H	0.1	0.1	0.2	0.3	0.5	0.7	1.3	2.2	4.1	2.4	3.4	114.0	6.0	1.0	0.8
NatWest Markets	0.1	3.2 L	0.6	0.4	0.1	0.2 H	0.2	0.3	0.4	0.8	1.5	2.9	3.8	3.3	3.1	111.0	20.2	1.4	2.9
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.4 H	0.5	0.7	na	na	na	na	na	na	30.0	1.5	1.5
Oxford Economics	0.1	3.3 H	0.6	na	0.2	0.2 H	0.2	0.3	0.5	0.8	1.7 H	1.8 L	na	na	3.3	115.1 H	27.0	1.1	0.4
PNC Financial Services Corp.	0.1	3.3 H	0.3 L	na	0.1	0.2 H	0.2	0.2	0.4	0.7	1.5	na	4.1	0.8 L	3.2	na	12.6	-1.5	-0.5
RDQ Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.2 H	0.2	0.2	0.6 H	0.9	1.6	2.6	3.9	3.4 H	3.4	114.3	12.2	2.7 H	3.6
Regions Financial Corporation	0.1	3.3 H	0.4	na	0.2	0.2 H	0.2	0.2	0.4	0.8	1.5	2.7	4.3	2.6	3.4	113.8	22.3	-0.5	3.9 H
S&P Global	0.1	3.3 H	0.6	na	0.2	0.2 H	0.2	0.3	0.6 H	1.0	1.7 H	na	na	na	3.5	na	24.1	-1.5	0.3
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.3	0.4	0.7	1.4	na	na	na	na	na	15.0	1.7	1.0
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2 H	0.3	0.4 H	0.6 H	1.0	1.7 H	3.4 H	5.7 H	na	2.7	na	25.0	na	0.6
The Northern Trust Company	0.1	3.3 H	0.6	0.2	0.2	0.2 H	0.2	0.3	0.5	0.8	1.4	2.5	3.6	3.2	3.1	112.5	18.4	0.6	0.5
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.2 H	0.2	0.2	0.3 L	0.6	1.3	2.0	3.0	1.2	2.6 L	115.0	9.5	0.5	-1.0
Wells Fargo	0.1	3.3 H	0.3 L	0.1 L	0.1	0.2 H	0.2	0.3	0.5	1.0	1.7 H	2.3	3.8	2.1	3.3	na	6.7	1.0	1.5
ING	0.0 L	na	0.4	na	na	na	na	0.2	0.4	1.3 H	1.3	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.3**	**0.1**	**0.2**	**0.2**	**0.3**	**0.4**	**0.8**	**1.5**	**2.6**	**4.0**	**2.6**	**3.3**	**113.6**	**15.2**	**1.0**	**1.3**
Top 10 Avg.	0.2	3.3	0.8	0.6	0.2	0.2	0.3	0.4	0.6	1.0	1.6	3.0	4.5	3.0	3.5	114.4	28.5	2.1	2.9
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.6	1.3	2.3	3.6	2.1	3.0	112.8	1.8	-0.3	-0.6
May Consensus	0.1	3.3	0.7	0.4	0.1	0.2	0.2	0.3	0.5	0.8	1.4	2.7	4.3	2.6	3.3	113.5	7.4	1.1	1.1
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	12	6	2	3	6	10	11	8	3	8	10	6	5	7	8	11	12
Same	38	29	15	13	27	23	21	28	25	24	18	8	6	6	16	6	8	13	11
Up	2	4	2	3	5	6	4	2	3	9	17	9	8	8	11	6	23	12	16
Diffusion Index	51%	56%	33%	43%	54%	55%	47%	40%	40%	51%	68%	52%	46%	55%	59%	47%	69%	51%	55%

Fourth Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.2	0.5	0.9	1.6	na	na	na	na	na	10.0	1.8	1.2
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.6	0.9	1.1	1.7	na	na	na	na	na	16.3	-0.7	1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.7	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	113.0	15.0	1.0	1.5
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.4	na	na	na	3.4	na	9.1	na	2.5
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.8 H	0.1	0.1	0.1	0.2	0.5	0.9	1.7	2.9	5.1	2.8	4.3 H	115.0	-2.0	1.0	-1.1 L
Action Economics	0.1	3.3 H	0.5	0.3	0.1	0.2	0.3	0.4	0.7	0.9	1.6	2.3	3.4	3.0	3.7	113.7	13.0	2.1	1.5
Amherst Pierpont Securities	0.1	3.3 H	0.5	0.1 L	0.2	0.3 H	0.4 H	0.8 H	1.0 H	1.4 H	2.1 H	3.2	4.6	3.1	3.9	114.5	7.1	2.2	2.8
Bank of America	0.1	na	0.5	na	na	na	na	0.5	0.7	1.0	1.6	na	na	na	na	na	12.0	0.7	0.1
Barclays	0.1	3.3 H	na	na	na	na	na	0.3	0.6	0.9	1.6	na	na	na	na	na	8.0	1.9	2.0
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2	0.3	0.4	0.6	0.9	1.5	na	na	na	2.8	114.4	5.0	1.7	2.0
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.5	na	1.3	na	na	na	na	na	na	10.0	na	1.7
Chan Economics	0.1	3.3 H	0.7	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.8	10.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.6	0.2	0.1	0.2	0.2	0.3	0.6	0.9	1.5	2.7	na	na	3.3	na	4.4	1.8	1.8
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	3.0	na	-2.6 L	1.3	1.3
Daiwa Capital Markets America	0.1	3.3 H	0.5	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.5	2.6	4.1	na	3.3	114.0	15.5	1.3	2.0
DePrince & Assoc.	0.1	3.3 H	0.4	0.3	0.1	0.1	0.1	0.2	0.3	0.8	1.4	3.0	4.0	2.6	3.0	111.9	6.7	1.2	1.2
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2	0.2	0.2	0.4	0.7	1.5	na	na	na	3.1	na	12.6	0.8	2.4
Georgia State University	0.1	3.3 H	na	na	-0.1 L	-0.2 L	0.0 L	0.1	0.5	0.9	1.6	3.6 H	4.8	na	3.6	na	1.0	1.8	2.2
GLC Financial Economics	0.1	3.3 H	0.3	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.9	4.2	2.9	3.6	110.0	4.1	1.8	2.0
Goldman Sachs & Co.	0.1	na	na	na	0.4 H	na	na	0.3	0.5	0.7	1.2 L	na	na	na	2.9	na	11.0	1.8	2.7
Grant Thornton/Diane Swonk	0.1	3.3 H	0.4	0.3	0.2	0.2	0.1	0.0 L	0.1 L	0.5 L	1.2 L	1.9 L	2.8	na	3.0	na	3.4	1.3	3.0
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.1	0.2	0.2	0.3	0.8	1.4	2.5	3.5	2.6	3.1	112.9	11.2	0.6	1.9
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	3.9	3.0	3.4	114.4	6.5	1.4	2.1
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.2	0.2	0.4 H	0.5	0.6	0.7	1.9	2.5	3.9	2.4	3.1	na	0.6	1.0	2.8
Moody's Capital Markets Group	0.1	3.3 H	0.6	0.3	0.1	0.1	0.2	0.2	0.3	0.7	1.3	2.5	3.9	3.0	3.3	115.2	7.6	1.4	1.9
MUFG Union Bank	0.1	3.3 H	0.2 L	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.8	3.2	115.0	7.0	1.5	2.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6	0.1	0.2	0.2	0.3	0.6	0.9	1.5	2.3	4.0	2.5	3.5	113.0	4.4	1.2	1.0
NatWest Markets	0.1	3.2 L	0.5	0.3	0.1	0.2	0.3	0.3	0.5	1.0	1.6	3.0	4.0	3.1	3.2	109.0 L	8.4	1.5	1.6
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.4	0.6	0.8	na	na	na	na	na	na	5.2	1.5	-0.6
Oxford Economics	0.1	3.3 H	0.4	na	0.2	0.2	0.2	0.3	0.7	1.1	1.8	2.0	na	na	3.3	115.1	11.0	2.3 H	2.0
PNC Financial Services Corp.	0.1	3.3 H	0.2 L	na	0.1	0.2	0.2	0.2	0.4	0.8	1.5	na	4.2	0.9 L	3.2	na	9.0	-0.9 L	0.4
RDQ Economics	0.1	3.3 H	0.3	0.2	0.1	0.2	0.2	0.2	0.7	1.1	1.9	2.7	4.0	3.6 H	3.4	113.8	9.6	2.3 H	2.5
Regions Financial Corporation	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.3	0.5	0.9	1.6	2.8	4.4	2.7	3.5	114.1	6.0	1.5	2.3
S&P Global	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.0	na	na	na	3.6	na	17.6 H	0.4	1.6
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.4	0.5	0.7	1.4	na	na	na	na	na	7.0	1.0	1.2
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.4	5.3 H	na	2.7	na	15.1	na	3.4 H
The Northern Trust Company	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.4	0.5	0.8	1.4	2.4	3.4	3.0	2.9	111.5	13.2	0.9	1.0
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.2	0.2	0.2	0.3	0.5 L	1.2 L	1.9 L	2.7 L	1.1	2.5 L	118.0 H	5.0	0.8	0.0
Wells Fargo	0.1	3.3 H	0.3	0.1 L	0.1	0.2	0.2	0.4	0.7	1.2	1.9	2.5	3.8	2.3	3.3	na	4.4	1.7	2.4
ING	0.0 L	na	0.4	na	na	na	na	0.3	0.5	1.4 H	1.4	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.1**	**0.2**	**0.2**	**0.3**	**0.5**	**0.9**	**1.5**	**2.7**	**4.0**	**2.6**	**3.3**	**113.6**	**8.2**	**1.3**	**1.7**
Top 10 Avg.	0.2	3.3	0.7	0.6	0.2	0.2	0.3	0.5	0.8	1.2	1.8	3.1	4.6	3.0	3.7	115.0	14.2	2.0	2.7
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.1	0.2	0.3	0.7	1.3	2.3	3.5	2.1	2.9	112.3	2.3	0.5	0.4
May Consensus	0.1	3.3	0.6	0.4	0.1	0.2	0.3	0.4	0.6	0.9	1.5	2.8	4.2	2.6	3.2	113.2	9.2	1.3	1.7
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	12	4	3	5	7	8	8	4	6	6	9	3	4	6	14	12	11
Same	38	29	15	14	27	21	21	30	29	29	16	11	5	9	15	7	10	15	17
Up	2	4	2	4	4	6	3	2	2	8	16	8	10	8	13	6	15	9	11
Diffusion Index	51%	56%	33%	50%	51%	52%	44%	43%	42%	55%	63%	54%	52%	63%	64%	50%	51%	46%	50%

First Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.3	0.6	1.0	1.8	na	na	na	na	na	6.0	1.7	1.4
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.7	1.0	1.2	1.9	na	na	na	na	na	10.0	1.3	5.0 H
Via Nova Investment Mgt.	0.3 H	3.3 H	0.6	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	4.0	1.7	3.3	112.0	4.0	1.5	2.0
Daiwa Capital Markets America	0.2	3.3 H	0.5	0.2	0.2	0.3	0.3	0.5	0.7	1.0	1.6	2.8	4.2	na	3.4	114.0	12.0	1.5	2.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.3	0.4	0.8	1.4	na	na	na	3.4	na	1.0 L	na	1.8
Regions Financial Corporation	0.2	3.3 H	0.5	na	0.2	0.3	0.4	0.3	0.6	1.0	1.7	2.9	4.4	2.7	3.6	114.7	4.3	1.1	1.8
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.8 H	0.1	0.1	0.1	0.2	0.5	1.0	2.0	3.2	6.7 H	2.6	4.0	113.0	6.5	0.9	3.9
Action Economics	0.1	3.3 H	0.5	0.3	0.2	0.3	0.4	0.5	0.7	1.0	1.7	2.3	3.4	3.0	3.7	113.5	8.0	1.5	2.4
Amherst Pierpont Securities	0.1	3.3 H	0.6	0.4	0.3	0.4 H	0.8 H	1.1 H	1.5 H	1.8 H	2.6 H	3.7	5.0	3.5	4.3 H	115.0	4.2	2.4	2.9
Bank of America	0.1	na	0.4	na	na	na	na	0.8	0.9	1.3	1.9	na	na	na	na	na	11.0	1.2	1.2
Barclays	0.1	3.3 H	na	na	na	na	na	0.3	0.6	1.0	1.7	na	na	na	na	na	5.0	1.6	1.3
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2	0.3	0.4	0.7	1.0	1.7	na	na	na	2.8	113.7	4.9	1.5	1.6
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.6	na	1.3	na	na	na	na	na	na	10.0	na	2.4
Chan Economics	0.1	3.3 H	0.6	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.9	5.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.7	0.2	0.1	0.2	0.2	0.4	0.6	1.0	1.6	2.7	na	na	3.4	na	3.1	1.9	2.1
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	3.0	na	5.0	1.6	1.9
DePrince & Assoc.	0.1	3.3 H	0.4	0.4	0.1	0.1	0.1	0.2	0.4	0.8	1.5	3.1	4.0	2.6	3.0	111.3	4.8	1.7	1.8
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2	0.2	0.2	0.5	0.8	1.5	na	na	na	3.0	na	8.7	1.2	2.8
Georgia State University	0.1	3.3 H	na	na	-0.1 L	-0.2 L	0.0 L	0.2	0.7	1.2	1.9	4.1 H	5.4	na	3.8	na	5.7	2.0	1.9
GLC Financial Economics	0.1	3.3 H	0.4	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.3	2.7	3.9	2.7	3.6	111.0	11.7	2.0	2.3
Goldman Sachs & Co.	0.1	na	na	na	0.4 H	na	na	na	na	0.8	na	na	na	na	2.9	na	8.0	1.4	2.2
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3	0.3	0.2	0.2	0.3	0.1 L	0.2 L	0.5	1.3	1.9	3.9	na	2.9	na	14.0 H	0.4	1.8
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.2	0.2	0.3	0.4	0.9	1.5	2.4	3.3	2.3	2.9	112.6	10.0	0.9	1.2
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	3.9	3.0	3.4	114.7	4.5	1.5	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.2	0.3	0.5	0.6	0.8	1.0	2.1	2.5	3.8	2.3	3.2	na	1.0 L	1.2	3.1
Moody's Capital Markets Group	0.1	3.3 H	0.5	0.3	0.1	0.1	0.2	0.2	0.4	0.8	1.4	2.6	4.1	2.7	3.2	115.7	6.4	1.5	1.9
MUFG Union Bank	0.1	3.3 H	0.2 L	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.7	3.1	116.0	5.0	1.5	2.3
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6	0.2	0.2	0.3	0.4	0.7	1.0	1.6	2.5	4.1	2.7	3.7	113.0	3.5	1.4	1.4
NatWest Markets	0.1	3.2 L	0.4	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.9	3.1	107.0 L	4.7	2.4	3.0
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.5	0.8	1.0	na	na	na	na	na	na	6.4	1.5	0.4 L
Oxford Economics	0.1	3.3 H	0.4	na	0.2	0.2	0.2	0.4	0.7	1.1	1.9	2.0	na	na	3.4	114.8	5.9	1.5	1.9
PNC Financial Services Corp.	0.1	3.3 H	0.2 L	na	0.1	0.2	0.2	0.2	0.5	0.8	1.6	na	4.2	1.0 L	3.1	na	7.6	-0.1 L	1.2
RDQ Economics	0.1	3.3 H	0.3	0.2	0.1	0.2	0.2	0.2	0.9	1.6	2.5	3.2	4.4	4.5 H	3.8	113.4	4.2	2.6	2.5
S&P Global	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	7.3	3.8 H	3.9
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.5	0.6	0.8	1.4	na	na	na	na	na	3.0	1.2	1.1
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.3	4.7	na	2.7	na	5.1	na	2.9
The Northern Trust Company	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.5	0.7	0.9	1.5	2.5	3.4	3.2	2.9	111.0	7.0	1.4	1.3
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.3	0.3	0.3	0.3	0.4 L	1.1 L	1.8 L	2.6 L	1.0 L	2.4 L	118.0 H	4.0	0.8	0.5
Wells Fargo	0.1	3.3 H	0.3	0.1 L	0.2	0.2	0.3	0.5	0.8	1.3	2.0	2.5	3.9	2.4	3.4	na	2.0	2.0	2.3
ING	0.0 L	na	0.4	na	na	na	na	0.6	0.8	1.7	1.7	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.2**	**0.2**	**0.3**	**0.4**	**0.6**	**1.0**	**1.7**	**2.7**	**4.2**	**2.6**	**3.3**	**113.4**	**6.2**	**1.5**	**2.1**
Top 10 Avg.	0.2	3.3	0.7	0.6	0.2	0.3	0.4	0.6	0.9	1.4	2.1	3.2	4.8	3.1	3.8	115.1	10.3	2.3	3.2
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.3	2.3	3.6	2.1	2.9	111.8	3.0	0.9	1.1
May Consensus	0.1	3.3	0.6	0.4	0.2	0.2	0.3	0.4	0.7	1.0	1.6	2.8	4.3	2.6	3.2	112.9	6.6	1.7	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	1	1	13	6	2	3	8	9	8	7	4	6	6	3	2	4	7	12	12
Same	38	28	14	13	28	23	20	27	27	27	17	11	10	12	19	8	12	15	15
Up	2	4	2	3	4	6	3	2	3	6	16	8	8	5	11	7	20	9	12
Diffusion Index	51%	55%	31%	43%	53%	55%	42%	41%	43%	49%	66%	54%	54%	55%	64%	58%	67%	46%	50%

Second Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Amherst Pierpont Securities	0.6 H	3.7 H	1.0	0.8	0.6 H	0.8 H	1.3 H	1.5 H	1.9 H	2.3 H	3.1 H	4.1	5.4	3.8	4.5 H	115.5	3.9	2.3	2.8
Daiwa Capital Markets America	0.5	3.7 H	0.8	0.5	0.5	0.6	0.7	0.9	1.1	1.4	2.0	3.1	4.6	na	3.8	114.0	8.0	1.7	2.1
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.5	1.7	1.4
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.8	1.1	1.3	2.1	na	na	na	na	na	6.3	2.8	0.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	3.8	1.5	3.3	110.0	3.5	2.0	2.2
Action Economics	0.2	3.3	0.6	0.4	0.3	0.4	0.4	0.5	0.8	1.0	1.7	2.3	3.4	3.0	3.7	113.5	6.5	2.0	2.5
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.2	0.3	0.4	0.8	1.4	na	na	na	3.5	na	1.4 L	na	1.9
Regions Financial Corporation	0.2	3.3	0.5	na	0.3	0.3	0.4	0.3	0.6	1.1	1.8	2.9	4.5	2.8	3.7	115.2	4.0	1.3	1.9
ACIMA Private Wealth	0.1	3.3	1.3 H	1.7 H	0.1	0.1	0.1	0.2 L	0.5	1.3	2.3	3.5	7.0 H	2.5	3.8	110.0	2.5	0.9	2.7
Bank of America	0.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	6.0	1.4	1.6
Barclays	0.1	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	1.9	1.9
BMO Capital Markets	0.1	3.3	0.4	na	0.1	0.2	0.3	0.5	0.8	1.1	1.8	na	na	na	2.9	113.0	4.7	1.4	1.4
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.8	na	1.3	na	na	na	na	na	na	7.5	na	2.8
Chan Economics	0.1	3.3	0.6	0.5	0.1	0.2	0.2	0.2 L	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.7	1.6	2.0	2.0
Chmura Economics & Analytics	0.1	3.3	0.8	0.2	0.1	0.2	0.2	0.4	0.6	1.1	1.6	2.7	na	na	3.4	na	4.3	2.0	2.2
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	2.9	na	4.2	1.9	2.0
DePrince & Assoc.	0.1	3.3	0.5	0.3	0.1	0.1	0.2	0.3	0.4	0.9	1.5	3.1	4.0	2.7	3.0	110.9	3.8	1.8	1.9
Fannie Mae	0.1	3.3	na	na	0.2	0.2	0.2	0.3	0.5	0.8	1.5	na	na	na	2.9	na	5.2	1.1	2.4
Georgia State University	0.1	3.3	na	na	-0.1 L	-0.2 L	0.0 L	0.2 L	0.8	1.4	2.1	4.4 H	5.8	na	4.0	na	4.6	0.8	2.1
GLC Financial Economics	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.2 L	2.5	3.8	2.5	3.6	110.8	9.7	1.9	2.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	na	na	1.0	na	na	na	na	2.9	na	6.5	1.2	1.7
Grant Thornton/Diane Swonk	0.1	3.3	0.3	0.3	0.1	0.2	0.3	0.2 L	0.1 L	0.4 L	1.2 L	1.8 L	2.8 L	na	2.7	na	10.1 H	0.9	2.0
Loomis, Sayles & Company	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	0.6	1.1	1.6	2.4	3.2	2.2	2.8	112.3	8.4	0.9	1.2
MacroFin Analytics & Rutgers Bus School	0.1	3.3	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.5	2.8	3.9	3.1	3.4	115.0	3.5	1.8	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.3	0.4	0.6	0.7	1.0	1.1	2.3	2.6	3.8	2.4	3.2	na	2.1	1.7	2.7
Moody's Capital Markets Group	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.2 L	0.4	0.9	1.5	2.6	4.0	2.6	3.1	116.3 H	4.5	1.7	0.9
MUFG Union Bank	0.1	3.3	0.2 L	na	0.1	0.1	0.2	0.2 L	0.4	0.7	1.4	2.5	4.0	2.6	3.1	116.0	2.5	1.5	2.6
Naroff Economic Advisors	0.1	3.3	1.2	1.7 H	0.2	0.3	0.5	0.6	0.8	1.2	1.8	2.8	4.2	2.9	3.9	112.0	2.3	1.7	1.7
NatWest Markets	0.1	3.2 L	0.3	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.7	2.9	106.0 L	3.7	2.3	2.0
Nomura Securities, Inc.	0.1	3.3	na	na	na	na	na	0.6	0.9	1.2	na	na	na	na	na	na	7.0	1.5	0.3 L
Oxford Economics	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.7	1.2	1.9	2.1	na	na	3.4	114.5	6.3	2.2	2.0
PNC Financial Services Corp.	0.1	3.3	0.2 L	na	0.1	0.2	0.2	0.2 L	0.5	0.9	1.7	na	4.3	1.1 L	3.0	na	6.0	0.6 L	1.4
RDQ Economics	0.1	3.3	0.3	0.2	0.1	0.2	0.2	0.2 L	1.2	2.1	3.0	3.7	4.8	5.1 H	4.2	113.4	4.2	2.7	2.6
S&P Global	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	4.3	5.6 H	4.5 H
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.6	0.7	0.8	1.4	na	na	na	na	na	2.5	1.2	1.5
Swiss Re	0.1	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7	na	2.0	na	1.0
The Northern Trust Company	0.1	3.3	0.5	0.2	0.2	0.3	0.3	0.5	0.8	1.1	1.7	2.7	3.6	3.4	3.1	110.8	5.6	1.6	1.5
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.3	0.4	0.4	0.5	0.6	1.3	2.0	2.8 L	1.2	2.6 L	115.0	3.0	0.8	0.5
Wells Fargo	0.1	3.3	0.3	0.1 L	0.2	0.3	0.3	0.6	0.9	1.3	2.0	2.5	3.9	2.5	3.4	na	2.3	1.9	1.2
ING	0.0 L	na	0.4	na	na	na	na	0.6	0.9	1.7	1.7	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.2**	**0.2**	**0.3**	**0.4**	**0.7**	**1.1**	**1.8**	**2.8**	**4.2**	**2.7**	**3.3**	**112.9**	**4.7**	**1.7**	**1.9**
Top 10 Avg.	0.3	3.4	0.8	0.7	0.3	0.4	0.5	0.8	1.1	1.5	2.3	3.4	5.0	3.2	3.9	114.9	7.6	2.6	2.8
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.3	3.5	2.1	2.8	110.9	2.2	1.0	1.0
May Consensus	0.2	3.3	0.6	0.5	0.2	0.3	0.4	0.5	0.7	1.1	1.7	2.9	4.2	2.6	3.3	112.5	4.8	1.9	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	2	1	9	6	4	6	8	10	11	7	5	6	6	5	3	3	11	13	16
Same	37	28	15	12	27	20	20	23	22	25	16	11	8	9	21	9	10	17	16
Up	2	4	3	4	3	6	3	2	2	5	13	8	10	6	8	7	18	6	7
Diffusion Index	50%	55%	39%	45%	49%	50%	42%	39%	37%	47%	62%	54%	58%	53%	58%	61%	59%	40%	38%

Third Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Amherst Pierpont Securities	1.1 H	4.2 H	1.6 H	1.2	1.1 H	1.3 H	1.8 H	1.9 H	2.3 H	2.7 H	3.4 H	4.4	5.7	4.0	4.8 H	116.0	3.5	2.4	2.8
Daiwa Capital Markets America	0.8	3.9	1.1	0.8	0.7	0.8	0.9	1.3	1.5	1.7	2.4	3.5	4.8	na	4.0	114.0	4.5	1.9	2.2
Action Economics	0.4	3.5	0.7	0.5	0.4	0.4	0.4	0.5	0.8	1.0	1.7	2.3	3.4	3.0	3.8	113.4	na	na	na
Naroff Economic Advisors	0.4	3.5	1.5	1.9 H	0.4	0.6	0.8	0.9	1.1	1.4	2.1	3.1	4.4	3.1	4.1	111.0	2.1	1.7	1.8
TS Lombard	0.4	3.5	0.6	0.4	0.4	0.6	0.7	0.8	0.9	1.0	1.7	2.5	3.3	1.6	3.0	110.0	2.5	1.0	0.8 L
Chmura Economics & Analytics	0.3	3.4	0.8	0.3	0.3	0.3	0.4	0.5	0.8	1.2	1.7	2.8	na	na	3.4	na	3.0	1.7	1.7
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.2	1.5
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.9	1.2	1.5	2.1	na	na	na	na	na	4.4	1.3	1.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	3.8	1.5	3.3	108.0	3.0	2.0	2.2
DePrince & Assoc.	0.2	3.4	0.6	0.5	0.2	0.2	0.3	0.4	0.6	1.0	1.6	3.2	4.1	2.7	3.1	110.5	3.4	1.8	1.9
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.3	0.3	0.5	1.0	1.5	na	na	na	3.5	na	2.1	na	2.2
Regions Financial Corporation	0.2	3.3	0.6	na	0.3	0.4	0.5	0.4	0.7	1.2	1.9	3.0	4.6	2.8	3.8	115.9	3.4	1.7	1.9
ACIMA Private Wealth	0.1	3.3	1.3	1.7	0.1	0.1	0.1 L	0.2 L	0.5	1.5	2.5	3.7	7.2 H	2.5	3.7	110.0	3.0	0.8	1.3
Bank of America	0.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.0	1.7	2.0
Barclays	0.1	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	2.3	2.5
BMO Capital Markets	0.1	3.3	0.4	na	0.1	0.2	0.3	0.5	0.9	1.2	1.9	na	na	na	3.0	112.2	4.1	1.4	1.5
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.9	na	1.4	na	na	na	na	na	na	5.0	na	2.5
Chan Economics	0.1	3.3	0.7	0.5	0.2	0.3	0.3	0.3	0.4	0.7	1.4	2.7	4.7	2.7	3.4	113.9	1.5 L	2.0	2.1
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.3	0.3	0.5	0.8	1.4	na	na	na	2.8	na	3.7	2.0	2.0
Fannie Mae	0.1	3.3	na	na	0.2	0.2	0.2	0.3	0.5	0.8	1.5	na	na	na	2.9	na	3.5	0.9	1.7
Georgia State University	0.1	3.3	na	na	-0.1 L	-0.2 L	0.1 L	0.4	1.1	1.7	2.5	4.7 H	6.2	na	4.2	na	4.0	0.3 L	1.9
GLC Financial Economics	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5	0.7	1.0 L	2.1	3.3	2.1	3.5	109.9	5.5	2.0	2.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	na	na	1.1	na	na	na	na	3.0	na	5.0	1.3	1.7
Grant Thornton/Diane Swonk	0.1	3.3	0.3	0.3	0.1	0.2	0.4	0.2 L	0.1 L	0.3 L	1.2	1.7 L	3.2	na	2.5 L	na	6.7	0.6	1.2
Loomis, Sayles & Company	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	0.7	1.2	1.6	2.3	3.1 L	2.2	2.8	112.1	5.3	0.9	1.3
MacroFin Analytics & Rutgers Bus School	0.1	3.3	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	4.0	3.1	3.4	115.5	2.0	2.0	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.7	0.1 L	0.4	0.5	0.7	0.9	1.1	1.3	2.4	2.7	3.7	2.4	3.3	na	7.6 H	1.5	3.1
Moody's Capital Markets Group	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.2 L	0.5	0.9	1.5	2.6	4.0	2.5	3.1	116.9	2.9	1.6	1.4
MUFG Union Bank	0.1	3.3	0.2 L	na	0.1	0.1	0.2	0.2 L	0.4	0.7	1.4	2.5	4.0	2.5	3.1	117.0 H	2.5	1.5	2.3
NatWest Markets	0.1	3.2 L	0.3	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.8	3.8	2.5	2.9	105.0 L	3.5	1.9	2.0
Nomura Securities, Inc.	0.1	3.3	na	na	na	na	na	0.7	1.1	1.4	na	na	na	na	na	na	5.9	1.5	0.9
Oxford Economics	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.8	1.2	2.0	2.1	na	na	3.5	113.9	7.2	2.1	2.0
PNC Financial Services Corp.	0.1	3.3	0.2 L	na	0.1	0.2	0.2	0.2 L	0.5	1.0	1.8	na	4.3	1.2 L	3.0	na	5.1	1.3	2.5
RDQ Economics	0.1	3.3	0.3	0.2	0.1	0.2	0.2	0.2 L	1.3	2.3	3.2	3.8	4.9	5.1 H	4.3	113.0	3.9	2.9	2.6
S&P Global	0.1	3.3	0.4	na	0.2	0.2	0.3	0.5	1.0	1.5	2.3	na	na	na	3.7	na	2.0	5.1 H	3.5 H
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.7	0.8	1.0	1.7	na	na	na	na	na	2.5	1.2	1.5
Swiss Re	0.1	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7	na	1.9	na	1.2
The Northern Trust Company	0.1	3.3	0.5	0.2	0.2	0.3	0.4	0.6	0.9	1.3	1.9	2.9	3.8	3.5	3.3	110.6	4.3	1.9	1.8
Wells Fargo	0.1	3.3	0.4	0.2	0.2	0.3	0.4	0.7	1.0	1.4	2.1	2.6	4.0	2.5	3.4	na	2.3	1.6	1.6
ING	0.0 L	na	0.4	na	na	na	na	0.9	1.2	1.9	1.9	na	na	na	na	na	na	na	na
June Consensus	**0.2**	**3.4**	**0.6**	**0.5**	**0.2**	**0.3**	**0.4**	**0.5**	**0.8**	**1.2**	**1.9**	**2.9**	**4.3**	**2.7**	**3.4**	**112.4**	**3.7**	**1.7**	**1.9**
Top 10 Avg.	0.5	3.5	1.0	0.8	0.5	0.6	0.7	1.0	1.3	1.8	2.5	3.5	5.1	3.3	4.0	115.0	5.8	2.5	2.6
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.3	3.5	2.1	2.9	109.9	2.1	1.0	1.3
May Consensus	0.2	3.4	0.7	0.6	0.3	0.3	0.4	0.6	0.8	1.2	1.8	3.0	4.3	2.6	3.3	112.2	3.6	1.8	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	6	3	8	5	7	9	10	10	13	8	6	7	6	6	5	4	6	13	15
Same	33	27	14	15	23	18	17	21	17	24	14	8	9	9	17	8	14	16	15
Up	2	3	5	2	4	5	4	4	5	5	14	10	9	5	10	7	18	6	8
Diffusion Index	45%	50%	44%	43%	46%	44%	40%	41%	39%	46%	62%	56%	56%	48%	58%	58%	66%	40%	41%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.13	0.13	0.13	0.75	0.90	1.00	--	--	--
BMO Capital Markets	0.13	0.13	0.13	0.75	0.85	1.10	115.1	114.5	113.0
IHSMarkit	--	--	--	0.66	0.66	0.67	--	--	--
ING Financial Markets	0.13	0.13	0.13	0.40	0.35	0.40	113.7	111.2	107.2
Mizuho Research Institute	--	--	--	0.70	0.75	0.80	--	--	--
Moody's Analytics	0.05	0.07	0.08	0.63	0.63	0.99	--	--	--
Moody's Capital Markets	0.13	0.13	0.13	0.72	0.75	0.85	114.8	115.1	116.0
Northern Trust	0.13	0.13	0.13	0.75	0.75	0.90	113.5	112.5	111.0
Oxford Economics	0.13	0.13	0.13	0.93	1.05	1.15	115.1	115.1	114.5
Scotiabank	0.13	0.13	0.13	0.85	1.05	1.30	--	--	--
TS Lombard	0.13	0.13	0.13	0.58	0.45	0.55	113.0	118.0	115.0
Wells Fargo	0.13	0.13	0.13	1.00	1.15	1.30	115.5	115.3	111.7
June Consensus	**0.12**	**0.12**	**0.13**	**0.73**	**0.78**	**0.92**	**114.4**	**114.5**	**112.6**
High	0.13	0.13	0.13	1.00	1.15	1.30	115.5	118.0	116.0
Low	0.05	0.07	0.08	0.40	0.35	0.40	113.0	111.2	107.2
Last Months Avg.	0.14	0.12	0.13	0.68	0.83	1.10	114.7	113.6	112.1

Japan

Blue Chip Forecasters	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.10	-0.10	-0.10	-0.05	0.00	0.00	107.0	104.0	105.0
BMO Capital Markets	-0.10	-0.10	-0.10	-0.05	-0.05	-0.10	108.0	110.0	112.0
IHSMarkit	--	--	--	--	--	--	107.8	109.9	112.1
ING Financial Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	106.0	105.0	105.0
Mizuho Research Institute	--	--	--	-0.05	0.00	0.00	107.0	108.0	109.0
Moody's Analytics	-0.10	-0.10	-0.10	-0.18	-0.47	-0.57	112.1	117.2	120.5
Moody's Capital Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	107.7	108.0	108.2
Nomura Securities	--	--	--	--	--	--	106.0	108.0	110.0
Northern Trust	-0.10	-0.10	-0.10	-0.05	-0.10	-0.05	109.0	108.0	108.0
Oxford Economics	-0.06	-0.06	-0.05	-0.11	-0.11	-0.09	106.3	106.0	106.0
Scotiabank	-0.10	-0.10	-0.10	--	--	--	107.0	107.0	106.0
TS Lombard	-0.06	-0.06	-0.06	0.00	0.00	0.00	107.7	108.0	110.0
Wells Fargo	-0.10	-0.10	-0.10	0.00	0.05	0.15	107.0	107.0	106.0
June Consensus	**-0.09**	**-0.09**	**-0.09**	**-0.05**	**-0.07**	**-0.07**	**107.6**	**108.2**	**109.1**
High	-0.06	-0.06	-0.05	0.00	0.05	0.15	112.1	117.2	120.5
Low	-0.10	-0.10	-0.10	-0.18	-0.47	-0.57	106.0	104.0	105.0
Last Months Avg.	-0.09	-0.09	-0.09	-0.11	-0.10	-0.07	108.6	108.6	109.4

United Kingdom

Blue Chip Forecasters	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	0.10	0.40	0.45	0.50	1.16	1.15	1.13
BMO Capital Markets	0.10	0.10	0.10	0.05	0.30	0.50	1.23	1.23	1.25
IHSMarkit	--	--	--	--	--	--	1.22	1.21	1.22
ING Financial Markets	0.10	0.10	0.10	0.75	1.00	1.25	1.21	1.22	1.31
Moody's Analytics	0.10	0.01	0.01	0.01	-0.14	0.09	1.26	1.30	1.40
Moody's Capital Markets	0.10	0.10	0.10	0.26	0.31	0.45	1.23	1.22	1.22
Nomura Securities	--	--	--	--	--	--	1.16	1.20	1.29
Northern Trust	0.10	0.10	0.10	0.30	0.35	0.40	1.23	1.24	1.28
Oxford Economics	0.10	0.10	0.10	0.40	0.48	0.67	1.25	1.26	1.28
Scotiabank	0.10	0.10	0.10	--	--	--	1.27	1.28	1.30
TS Lombard	0.10	0.10	0.10	0.19	0.25	0.30	1.24	1.18	1.15
Wells Fargo	0.10	0.10	0.10	0.40	0.55	0.75	1.20	1.21	1.24
June Consensus	**0.10**	**0.09**	**0.09**	**0.31**	**0.39**	**0.55**	**1.22**	**1.23**	**1.26**
High	0.10	0.10	0.10	0.75	1.00	1.25	1.27	1.30	1.40
Low	0.10	0.01	0.01	0.01	-0.14	0.09	1.16	1.15	1.13
Last Months Avg.	0.10	0.09	0.09	0.32	0.34	0.54	1.23	1.24	1.28

Switzerland

Blue Chip Forecasters	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.97	0.98	0.99
ING Financial Markets	-0.75	-0.75	-0.75	-0.40	-0.35	-0.30	0.95	0.94	0.94
Moody's Analytics	-0.75	-0.75	-0.75	-1.15	-1.06	-0.98	0.96	0.91	0.85
Moody's Capital Markets	-0.75	-0.75	-0.75	-0.50	-0.48	-0.45	0.97	0.98	0.98
Nomura Securities	--	--	--	--	--	--	0.96	0.95	0.95
Northern Trust	-0.75	-0.75	-0.75	-0.50	-0.45	-0.40	0.96	0.97	0.99
Oxford Economics	-0.75	-0.75	-0.75	-0.40	-0.36	-0.28	1.00	1.01	1.02
Scotiabank	--	--	--	--	--	--	0.95	0.94	0.93
TS Lombard	-0.75	-0.75	-0.75	-0.50	-0.50	-0.50	0.97	0.97	0.97
Wells Fargo	--	--	--	--	--	--	0.99	0.98	0.95
June Consensus	**-0.75**	**-0.75**	**-0.75**	**-0.58**	**-0.53**	**-0.49**	**0.97**	**0.96**	**0.96**
High	-0.75	-0.75	-0.75	-0.40	-0.35	-0.28	1.00	1.01	1.02
Low	-0.75	-0.75	-0.75	-1.15	-1.06	-0.98	0.95	0.91	0.85
Last Months Avg.	-0.75	-0.75	-0.75	-0.53	-0.51	-0.47	0.96	0.96	0.96

Canada

Blue Chip Forecasters	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
BMO Capital Markets	0.25	0.25	0.25	0.65	0.75	1.00	1.42	1.41	1.38
IHSMarkit	--	--	--	--	--	--	1.39	1.38	1.36
ING Financial Markets	0.25	0.25	0.25	0.75	0.75	1.00	1.40	1.35	1.27
Moody's Analytics	0.04	0.25	0.25	0.61	0.57	0.96	1.45	1.43	1.36
Moody's Capital Markets	0.25	0.25	0.25	0.58	0.60	0.62	1.39	1.40	1.41
Nomura Securities	--	--	--	--	--	--	1.45	1.40	1.37
Northern Trust	0.25	0.25	0.25	0.60	0.70	0.80	1.39	1.36	1.33
Oxford Economics	0.25	0.25	0.25	0.85	1.04	1.29	1.46	1.45	1.44
Scotiabank	0.25	0.25	0.25	0.90	1.00	1.30	1.39	1.38	1.35
TS Lombard	0.25	0.25	0.25	0.53	0.43	0.50	1.38	1.38	1.38
Wells Fargo	0.25	0.25	0.25	0.80	0.90	1.15	1.43	1.43	1.41
June Consensus	**0.23**	**0.25**	**0.25**	**0.70**	**0.75**	**0.96**	**1.41**	**1.40**	**1.37**
High	0.25	0.25	0.25	0.90	1.04	1.30	1.46	1.45	1.44
Low	0.04	0.25	0.25	0.53	0.43	0.50	1.38	1.35	1.27
Last Months Avg.	0.25	0.25	0.25	0.68	0.80	1.10	1.44	1.41	1.38

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.63	0.63	0.63
ING Financial Markets	0.25	0.25	0.50	--	--	--	0.63	0.66	0.71
Moody's Analytics	0.25	0.25	0.25	0.85	0.62	0.76	0.63	0.62	0.66
Moody's Capital Markets	0.25	0.25	0.25	0.93	0.97	1.05	0.66	0.65	0.65
Nomura Securities	--	--	--	--	--	--	0.62	0.61	0.63
Northern Trust	0.25	0.25	0.25	1.00	1.10	1.20	0.65	0.66	0.67
Oxford Economics	0.25	0.25	0.25	0.85	0.85	0.85	0.65	0.65	0.66
Scotiabank	0.25	0.25	0.25	--	--	--	0.62	0.63	0.66
TS Lombard	0.25	0.25	0.25	0.90	0.80	0.70	0.66	0.66	0.66
Wells Fargo	--	--	--	--	--	--	0.62	0.62	0.64
June Consensus	**0.25**	**0.25**	**0.29**	**0.91**	**0.87**	**0.91**	**0.64**	**0.64**	**0.66**
High	0.25	0.25	0.50	1.00	1.10	1.20	0.66	0.66	0.71
Low	0.25	0.25	0.25	0.85	0.62	0.70	0.62	0.61	0.63
Last Months Avg.	0.25	0.25	0.25	0.68	0.69	0.88	0.62	0.63	0.65

Euro area

Blue Chip Forecasters	Main Refinancing Rate			US$ per Euro		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.00	0.00	0.00	1.08	1.06	1.02
BMO Capital Markets	0.00	0.00	0.00	1.06	1.08	1.10
IHSMarkit	--	--	--	1.09	1.08	1.08
ING Financial Markets	0.00	0.00	0.00	1.10	1.12	1.15
Moody's Analytics	0.00	0.00	0.00	1.10	1.16	1.25
Moody's Capital Markets	0.00	0.00	0.00	1.08	1.08	1.07
Nomura Securities	--	--	--	1.07	1.09	1.12
Northern Trust	0.00	0.00	0.00	1.10	1.12	1.14
Oxford Economics	0.00	0.00	0.00	1.08	1.08	1.08
Scotiabank	0.00	0.00	0.00	1.10	1.12	1.14
TS Lombard	0.00	0.00	0.00	1.10	1.08	1.12
Wells Fargo	0.00	0.00	0.00	1.06	1.07	1.11
June Consensus	**0.00**	**0.00**	**0.00**	**1.09**	**1.10**	**1.12**
High	0.00	0.00	0.00	1.10	1.16	1.25
Low	0.00	0.00	0.00	1.06	1.06	1.02
Last Months Avg.	-0.05	-0.05	-0.05	1.09	1.10	1.12

10 Yr. Gov't Bond Yields %

Blue Chip Forecasters	Germany			France			Italy			Spain		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.60	-0.55	-0.50	--	--	--	--	--	--	--	--	--
BMO Capital Markets	-0.35	-0.20	-0.05	--	--	--	--	--	--	--	--	--
ING Financial Markets	--	--	--	-0.40	-0.35	-0.20	1.40	1.35	1.40	0.40	0.45	0.60
Moody's Analytics	-0.61	-0.56	-0.37	-0.13	-0.14	-0.06	2.31	1.93	1.76	0.84	0.99	0.66
Moody's Capital Markets	-0.40	-0.38	-0.30	0.04	0.05	0.18	1.59	1.60	1.65	0.72	0.73	0.85
Northern Trust	-0.50	-0.40	-0.30	0.00	0.05	0.10	1.70	1.60	1.50	0.70	0.60	0.50
Oxford Economics	-0.31	-0.24	-0.10	0.17	0.25	0.40	1.84	1.86	2.00	1.04	1.11	1.40
TS Lombard	-0.42	-0.50	-0.60	0.00	-0.08	-0.18	1.50	1.42	1.32	0.60	0.52	0.42
Wells Fargo	-0.40	-0.30	-0.10	--	--	--	--	--	--	--	--	--
June Consensus	**-0.45**	**-0.39**	**-0.29**	**-0.05**	**-0.04**	**0.04**	**1.72**	**1.63**	**1.61**	**0.72**	**0.73**	**0.74**
High	-0.31	-0.20	-0.05	0.17	0.25	0.40	2.31	1.93	2.00	1.04	1.11	1.40
Low	-0.61	-0.56	-0.60	-0.40	-0.35	-0.20	1.40	1.35	1.32	0.40	0.45	0.42
Last Months Avg.	-0.47	-0.41	-0.27	0.03	0.05	0.11	1.81	1.74	1.69	0.80	0.76	0.76

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.66	-0.78	-0.85	-0.98
United Kingdom	-0.45	-0.42	-0.38	-0.37
Switzerland	-1.17	-1.30	-1.31	-1.40
Canada	-0.15	-0.03	-0.03	0.04
Australia	0.21	0.18	0.09	-0.01
Germany	-1.15	-1.18	-1.17	-1.21
France	-0.70	-0.78	-0.82	-0.88
Italy	0.96	1.00	0.85	0.69
Spain	0.02	-0.01	-0.04	-0.18

Consensus Forecasts
Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.23	-0.21	-0.03	-0.22
United Kingdom	-0.03	-0.02	-0.03	-0.03
Switzerland	-0.88	-0.87	-0.87	-0.88
Canada	0.13	0.10	0.13	0.13
Australia	0.13	0.13	0.13	0.16
Euro area	-0.13	-0.12	-0.12	-0.13

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Special Questions

1. a. What do you think the peak monthly unemployment rate might be?

20.3%

b. What month would that happen?

May	Jun	Jul	Aug	Oct
61%	24%	6%	6%	3%

c. What do you think the U.S. unemployment rate will be:

at the end of 2020? 11.0%

at the end of 2021? 7.2%

2. The House of Representatives has voted for another $3 trillion in COVID-related federal aid for the economy. Senate passage of this exact bill is, however, open for negotiation.

a. How much more aid do you believe is needed for meaningful support of the economy?

$2.4 trillion

b. The federal government budget deficit was just under $1.0 trillion in fiscal 2019, which was 4.6% of GDP. How large do you see the budget deficit this year and next, and what percentage of GDP would that be?

FY 2020? $4.0 trillion % of GDP 18.9%

FY 2021? $2.5 trillion % of GDP 10.9%

3. The Federal Reserve continues to add substantial amounts to its balance sheet as it seeks to provide credit and/or to support lending by private institutions. By mid-May, its total assets were $6.9 trillion. How large do you estimate the Fed's balance sheet at

Year-end 2020? $9.4 trillion

Year-end 2021? $10.2 trillion

Assessing Credit Losses and Risks to the Banking System

With businesses shuttered and job losses mounting rapidly, there is growing concern over the ability of borrowers to service their debt obligations and the resulting risks to financial stability. We assess the likely scale of economy-wide credit losses, the exposure of creditors to those losses, and the potential risks to financial stability and the banking sector in this edition of the Analyst.

Assessing Credit Losses. We first look at corporate debt. Nonfinancial corporate debt grew by over 60% since 2011 and recently rose to an all-time high as a share of GDP, leading to growing concern even prior to the virus that corporate defaults could rise dramatically in the next downturn. The sharp decline in revenues across many industries has left a large share of companies with negative cash flow, and rising bankruptcy filings and cases suggest the corporate default cycle has started.

A unique feature of this downturn is the wide variation in industry exposure to the virus, with physical constraints on spending, occupational health risks, and geographical variation in the virus outbreak affecting industries differently. Assessing the likely scale of corporate credit losses thus requires a closer look at which industries are most affected and how large they are as share of total corporate debt, as virus-exposure will likely play a large role in determining credit losses alongside traditional cyclical factors.

To assess the impact of the virus across industries, we first look at changes in credit spreads from before the virus to the present for high-yield corporate bonds at the granular industry level. We categorize industries as directly impacted by the virus or only indirectly impacted by the virus, based on a breakdown by our credit strategists and our assessment of which industries have been hardest hit by the virus thus far. Looking across roughly 80 industries, we find that the energy sector and industries directly impacted by the virus have seen significantly larger increases in credit spreads. While translating these numbers to default risk remains challenging given changes in risk premiums, they suggest that default rates will largely be driven by industry exposure to the virus.

The energy sector stands out both in terms of its size and default risks, given the collapse in oil demand, its disproportionately large footprint in the corporate bond market relative to its GDP share, and the heavy amounts of leverage in the sector. We estimate that roughly half of high-yield corporate bonds are in the energy or virus-impacted industries. Overall, our credit strategists estimate that the 12-month trailing high-yield default rate will increase to 13% by the end of 2020, similar to the peak rate reached during the Global Financial Crisis.

Another key area of concern is commercial real estate (CRE), given signs of overheating and overstretched valuations prior to the virus, as well as the unprecedented declines in demand in industries such as lodging, healthcare, and retail. Commercial real estate prices have outpaced single family house prices since the prior downturn, with CRE capitalization rates falling to historically low levels. Late payments on commercial mortgages have picked up sharply in recent months, suggesting mounting pressures.

Once again, the unique nature of this downturn suggests that variation in virus exposure will play a large role in determining the breadth and depth of credit losses in commercial real estate. Delinquencies by property type already show wide dispersion, with virus-exposed property types such as lodging and retail showing much higher delinquency rates

than less exposed property types such as self-storage. This contrasts with the prior real estate bust, when delinquencies were roughly evenly distributed across property types. Overall, our housing strategists expect a deeper contraction of property incomes than during the financial crisis period, given the heavy stresses to rents and occupancy rates facing many properties, and overall losses on commercial mortgages similar to those observed during the financial crisis.

In contrast to corporate debt, consumer debt should see lower default and delinquency rates thanks to strong household balance sheets, expanded unemployment benefits and stimulus payments, and public and private forbearance provisions. Early signs suggest the policy response is helping most consumers stay current on their bills. For these reasons, our housing strategists also expect significantly smaller losses on residential loans than during the prior downturn. Nevertheless, significant downside risks to household debt remain, particularly if unemployment insurance benefits are not extended, and if higher out-of-pocket medical expenses due to loss of employer-based health insurance push more households to default.

Who Bears the Losses? We next look to see where credit losses are most likely to be felt. The Fed's Financial Accounts suggests that the banking system plays a large role in providing credit for commercial real estate and overall corporate borrowing, two areas of greater concern. Household debt is also largely held by banks, particularly residential mortgages, credit card loans, and auto loans, while student debt is largely held by the federal government.

Municipal debt, another area of concern, is largely held by households, mutual funds and pensions funds, and insurance companies, and thus likely poses a smaller threat to financial stability. Lastly, a growing share of corporate lending—especially in riskier categories, such as leveraged loans—is now done by nonbank financial institutions, including collateralized loan obligations (CLOs), asset managers, hedge funds, and private equity companies, and such lending is not well captured in the Fed's Financial Accounts. TIC data provides some evidence that non-bank financial institutions and insurance companies own much of US CLO securities, a growing area of concern. Crucially, CLOs do not generally permit early redemptions and are thus less susceptible to runs, and our credit strategists do not see CLOs posing a major risk to financial stability, despite the likely significant pickup in defaults on leveraged loans.

Banks are highly exposed to many areas of credit, while households, mutual funds, and pensions are largely more exposed to equities. Insurance companies are somewhere in between, and hold a significant amount of exposure to corporate debt, including CLOs.

Given the large size of the banking system, its importance in credit provision, and its outsized role in amplifying the economic shocks of the last downturn, we next turn to assessing the risks of the credit downturn to the banking system.

Risks to the Banking System. The Fed's Financial Stability Report warned that financial sector vulnerabilities, including for the banking sector, are likely to be significant in the near term, while the April FOMC minutes indicated concern that banks could come under greater stress, particularly if more adverse economic scenarios were realized. The Fed's Senior Loan Officer Opinion Survey (SLOOS) indicated that lending standards tightened significantly, particularly for commercial and industrial (C&I) and CRE loans, with most banks citing a less favorable or more uncertain economic outlook, as well as a reduced tolerance for risk, as reasons for tightening lending standards. Loan loss provisions across banks have increased significantly in preparation for the rise in defaults and delinquencies.

While further losses are likely to come, there are several reasons why banks may prove more resilient than during the financial crisis. The banking system is much better capitalized, with capital ratios comfortably above their required minimum levels. Only a modest percentage of banks cited a deterioration in their capital position as playing a role in tightening lending standards in the first quarter. In addition, residential real estate remains the largest category of lending in the banking system by a significant margin. Given that this downturn was not precipitated by a housing crisis, losses on this particularly large category will likely be smaller than during the GFC.

One potential worry is that certain industries are heavily exposed to the virus, which may lead to larger risks to the banking system if the lending of particular banks, or the banking system as a whole, is highly concentrated in these industries. Disclosures on industry exposure provided by relatively large banks suggest that the exposure of the banking system to at-risk industries appears manageable. Moreover, most individual large banks are not heavily concentrated in at-risk industries, although smaller banks may be more geographically constrained and thus concentrated in particular industries.

We next assess the vulnerability of bank balance sheets as of 2019Q4, using comprehensive balance sheet data across all FDIC-insured institutions. We estimate the losses on total bank equity from losses across asset categories, based on projections from our bank and credit analysts and our economic projections. We assume similar losses on C&I and CRE lending as in the 2008 crisis, but a smaller hit on residential mortgages and consumer loans. Crucially, we do not build in large effects from the fiscal stimulus package, which should ease the burden of losses for the private sector, especially for household and small business loans.

We calculate the estimated losses as a percent of total bank equity capital, using our outlined assumptions. We estimate that losses on C&I, CRE, consumer, and residential real estate loans would amount to roughly 15% of total bank equity, compared to around 30% of total bank equity at risk heading into the Global Financial Crisis, using ex-post realized losses across the same categories. Two main reasons account for this difference: first, losses on the large residential real estate category are likely to be smaller, and second, bank equity levels are higher today than before the crisis.

We next look at lending exposure of the largest banks individually, using bank-specific details from regulatory data covering all large banks operating in the US. Bank-level data can reveal differences across banks and highlight whether there are a significant number of banks with large exposures to at-risk categories. We again compare the largest banks' exposure across major loan categories today to their exposure across these categories in 2007. Where available, we use bank-level disclosures on exposures to high-risk industries, applying a higher loss rate for banks with higher exposures.

We find that while there is dispersion among the largest banks in their exposure to losses, almost all of the largest banks today are less vulnerable than the median large bank was prior to the financial crisis. Again, our finding is driven by both the smaller losses in the large real estate category and by banks' higher equity capital levels today.

While financial stability concerns appear manageable, significant downside risks remain. A slower than expected recovery and a prolonged downturn would likely stress the banking system further, and a growing share of riskier lending is now done by less regulated nonbank financial institutions, where risks are harder to assess. Should a more adverse scenario arise, Fed officials have indicated the willingness to further help facilitate the provision of credit by the financial system.

David Choi (Goldman Sachs)

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2021 through 2026 and averages for the five-year periods 2022-2026 and 2027-2031. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2021	2022	2023	2024	2025	2026	2022-2026	2027-2031
1. Federal Funds Rate	**CONSENSUS**	**0.2**	**0.4**	**1.0**	**1.6**	**1.9**	**2.1**	**1.4**	**2.3**
	Top 10 Average	0.4	0.8	1.6	2.2	2.5	2.7	1.9	2.8
	Bottom 10 Average	0.1	0.1	0.4	1.0	1.3	1.5	0.9	1.7
2. Prime Rate	**CONSENSUS**	**3.4**	**3.6**	**4.1**	**4.7**	**5.0**	**5.2**	**4.5**	**5.4**
	Top 10 Average	3.5	3.9	4.6	5.3	5.5	5.7	5.0	5.9
	Bottom 10 Average	3.3	3.3	3.7	4.2	4.5	4.7	4.1	4.9
3. LIBOR, 3-Mo.	**CONSENSUS**	**0.6**	**0.9**	**1.4**	**2.0**	**2.3**	**2.4**	**1.8**	**2.6**
	Top 10 Average	0.8	1.3	1.9	2.5	2.7	3.0	2.3	3.1
	Bottom 10 Average	0.4	0.5	0.9	1.6	1.9	2.0	1.4	2.1
4. Commercial Paper, 1-Mo	**CONSENSUS**	**0.6**	**0.9**	**1.4**	**2.0**	**2.2**	**2.3**	**1.7**	**2.6**
	Top 10 Average	0.7	1.2	1.8	2.3	2.6	2.8	2.1	3.0
	Bottom 10 Average	0.3	0.5	1.1	1.6	1.9	2.0	1.4	2.2
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**0.2**	**0.5**	**1.1**	**1.6**	**1.9**	**2.1**	**1.4**	**2.3**
	Top 10 Average	0.4	0.9	1.6	2.2	2.4	2.6	1.9	2.8
	Bottom 10 Average	0.1	0.2	0.5	1.1	1.4	1.6	0.9	1.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**0.3**	**0.6**	**1.1**	**1.7**	**2.0**	**2.2**	**1.5**	**2.5**
	Top 10 Average	0.4	0.9	1.7	2.3	2.6	2.7	2.0	3.0
	Bottom 10 Average	0.2	0.2	0.6	1.2	1.5	1.7	1.1	1.9
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**0.4**	**0.7**	**1.3**	**1.8**	**2.1**	**2.3**	**1.7**	**2.6**
	Top 10 Average	0.5	1.1	1.8	2.4	2.7	2.9	2.2	3.1
	Bottom 10 Average	0.2	0.3	0.7	1.3	1.6	1.8	1.1	2.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**0.5**	**0.9**	**1.5**	**2.0**	**2.3**	**2.5**	**1.8**	**2.7**
	Top 10 Average	0.8	1.3	2.0	2.5	2.9	3.0	2.4	3.3
	Bottom 10 Average	0.3	0.4	0.9	1.4	1.7	2.0	1.3	2.2
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**0.7**	**1.1**	**1.7**	**2.2**	**2.5**	**2.7**	**2.0**	**2.9**
	Top 10 Average	1.1	1.6	2.3	2.8	3.1	3.3	2.6	3.5
	Bottom 10 Average	0.5	0.7	1.2	1.6	1.8	2.1	1.5	2.3
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**1.2**	**1.5**	**2.1**	**2.5**	**2.7**	**2.9**	**2.3**	**3.1**
	Top 10 Average	1.5	2.0	2.6	3.1	3.3	3.5	2.9	3.8
	Bottom 10 Average	0.8	1.1	1.6	1.9	2.1	2.2	1.8	2.5
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**1.8**	**2.2**	**2.7**	**3.1**	**3.3**	**3.5**	**3.0**	**3.8**
	Top 10 Average	2.2	2.7	3.3	3.7	3.9	4.1	3.5	4.4
	Bottom 10 Average	1.4	1.7	2.2	2.6	2.8	2.9	2.4	3.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**2.8**	**3.2**	**3.6**	**4.0**	**4.2**	**4.3**	**3.9**	**4.6**
	Top 10 Average	3.1	3.6	4.2	4.6	4.7	4.8	4.4	5.1
	Bottom 10 Average	2.4	2.7	3.1	3.5	3.7	3.8	3.4	4.2
13. Corporate Baa Bond Yield	**CONSENSUS**	**4.1**	**4.5**	**4.9**	**5.2**	**5.3**	**5.4**	**5.0**	**5.7**
	Top 10 Average	4.6	5.0	5.4	5.7	5.8	6.0	5.6	6.2
	Bottom 10 Average	3.6	3.9	4.3	4.6	4.7	4.8	4.4	5.2
14. State & Local Bonds Yield	**CONSENSUS**	**2.6**	**3.0**	**3.5**	**3.7**	**3.8**	**3.8**	**3.6**	**4.1**
	Top 10 Average	3.0	3.3	3.9	4.2	4.3	4.4	4.0	4.6
	Bottom 10 Average	2.3	2.6	2.9	3.2	3.2	3.3	3.0	3.7
15. Home Mortgage Rate	**CONSENSUS**	**3.4**	**3.6**	**4.0**	**4.4**	**4.5**	**4.7**	**4.2**	**4.9**
	Top 10 Average	3.8	4.0	4.5	4.8	5.0	5.2	4.7	5.5
	Bottom 10 Average	3.0	3.2	3.5	3.9	4.1	4.1	3.7	4.4
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**112.8**	**112.6**	**112.5**	**111.8**	**111.4**	**111.0**	**111.9**	**110.6**
	Top 10 Average	114.1	114.5	114.1	113.8	113.5	113.4	113.9	113.9
	Bottom 10 Average	111.7	110.7	110.7	110.2	109.5	108.7	110.0	107.6
		Year-Over-Year, % Change						Five-Year Averages	
		2021	2022	2023	2024	2025	2026	2022-2026	2027-2031
B. Real GDP	**CONSENSUS**	**3.2**	**3.2**	**2.4**	**2.2**	**2.1**	**2.0**	**2.4**	**2.1**
	Top 10 Average	5.7	4.3	2.9	2.5	2.3	2.3	2.9	2.4
	Bottom 10 Average	0.5	2.2	1.9	1.9	1.8	1.8	1.9	1.8
C. GDP Chained Price Index	**CONSENSUS**	**1.1**	**1.7**	**1.9**	**2.0**	**2.0**	**2.0**	**1.9**	**2.0**
	Top 10 Average	1.8	2.2	2.2	2.2	2.3	2.2	2.2	2.2
	Bottom 10 Average	0.3	1.3	1.6	1.8	1.8	1.8	1.7	1.9
D. Consumer Price Index	**CONSENSUS**	**1.3**	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.2**
	Top 10 Average	2.2	2.5	2.3	2.3	2.4	2.3	2.4	2.4
	Bottom 10 Average	0.4	1.5	1.8	1.8	1.9	1.9	1.8	2.0

Databank:

2020 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	-0.4	-8.3	-16.4	....	....	....	....	....	....	....	....
Auto & Light Truck Sales (b)	16.93	16.75	11.36	8.58	....	....	....	....	....	....	....	....
Personal Income (a, current $)	0.5	0.6	-2.0	....	....	....	....	....	....	....	....	....
Personal Consumption (a, current $)	0.4	0.2	-7.5	....	....	....	....	....	....	....	....	....
Consumer Credit (e)	3.0	5.7	-3.4	....	....	....	....	....	....	....	....	....
Consumer Sentiment (U. of Mich.)	99.8	101.0	89.1	71.8	73.7	....	....	....	....	....	....	....
Household Employment (c)	-89	45	-2987	-22369	....	....	....	....	....	....	....	....
Nonfarm Payroll Employment (c)	214	251	-881	-20537	....	....	....	....	....	....	....	....
Unemployment Rate (%)	3.6	3.5	4.4	14.7	....	....	....	....	....	....	....	....
Average Hourly Earnings (All, cur. $)	28.43	28.52	28.67	30.01	....	....	....	....	....	....	....	....
Average Workweek (All, hrs.)	34.3	34.4	34.1	34.2	....	....	....	....	....	....	....	....
Industrial Production (d)	-0.9	-0.3	-4.9	-15.0	....	....	....	....	....	....	....	....
Capacity Utilization (%)	76.7	76.7	73.2	64.9	....	....	....	....	....	....	....	....
ISM Manufacturing Index (g)	50.9	50.1	49.1	41.5	....	....	....	....	....	....	....	....
ISM Nonmanufacturing Index (g)	55.5	57.3	52.5	41.8	....	....	....	....	....	....	....	....
Housing Starts (b)	1.617	1.567	1.276	0.891	....	....	....	....	....	....	....	....
Housing Permits (b)	1.536	1.438	1.356	1.066	....	....	....	....	....	....	....	....
New Home Sales (1-family) (h)	774	717	619	623	....	....	....	....	....	....	....	....
Construction Expenditures (a)	2.6	-2.5	0.9	....	....	....	....	....	....	....	....	....
Consumer Price Index (nsa, d)	2.5	2.3	1.5	0.3	....	....	....	....	....	....	....	....
CPI ex. Food and Energy (nsa, d)	2.3	2.4	2.1	1.4	....	....	....	....	....	....	....	....
Producer Price Index (nsa, d)	2.1	1.3	0.7	-1.2	....	....	....	....	....	....	....	....
Durable Goods Orders (a)	-0.2	2.0	-16.6	-17.2	....	....	....	....	....	....	....	....
Leading Economic Indicators (a)	0.4	-0.2	-7.4	-4.4	....	....	....	....	....	....	....	....
Balance of Trade & Services (f)	-45.5	-39.8	-44.4	....	....	....	....	....	....	....	....	....
Federal Funds Rate (%)	1.55	1.58	0.65	0.05	....	....	....	....	....	....	....	....
3-Mo. Treasury Bill Rate (%)	1.55	1.54	0.30	0.14	....	....	....	....	....	....	....	....
10-Year Treasury Note Yield (%)	1.76	1.50	0.87	0.66	....	....	....	....	....	....	....	....

2019 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.5	-0.1	1.6	0.5	0.4	0.4	0.6	0.4	-0.4	0.5	0.0	0.1
Auto & Light Truck Sales (b)	16.71	16.52	17.26	16.48	17.39	17.18	16.88	16.97	17.15	16.52	16.99	16.65
Personal Income (a, current $)	0.3	0.6	0.4	0.3	0.2	0.4	0.0	0.4	0.2	0.1	0.5	0.2
Personal Consumption (a, current $)	0.6	-0.1	1.0	0.7	0.4	0.3	0.5	0.3	0.2	0.3	0.3	0.4
Consumer Credit (e)	5.2	4.8	3.6	5.1	4.3	3.5	6.7	4.5	3.1	3.9	2.1	6.1
Consumer Sentiment (U. of Mich.)	91.2	93.8	98.4	97.2	100.0	98.2	98.4	89.8	93.2	95.5	96.8	99.3
Household Employment (h)	-198	239	-125	-45	148	304	198	549	403	246	-8	267
Nonfarm Payroll Employment (c)	269	1	147	210	85	182	194	207	208	185	261	184
Unemployment Rate (%)	4.0	3.8	3.8	3.6	3.6	3.7	3.7	3.7	3.5	3.6	3.5	3.5
Average Hourly Earnings (All, cur. $)	27.58	27.69	27.76	27.81	27.87	27.96	28.05	28.16	28.16	28.24	28.34	28.37
Average Workweek (All, hrs.)	34.5	34.4	34.5	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.3	34.3
Industrial Production (d)	3.6	2.7	2.3	0.7	1.7	1.0	0.4	0.3	-0.2	-0.8	-0.4	-0.8
Capacity Utilization (%)	79.0	78.5	78.4	77.8	77.8	77.7	77.4	77.8	77.4	77.0	77.6	77.2
ISM Manufacturing Index (g)	55.5	54.1	54.6	53.4	52.3	51.6	51.3	48.8	48.2	48.5	48.1	47.8
ISM Nonmanufacturing Index (g)	56.0	58.5	56.3	55.7	56.3	55.4	54.8	56.0	53.5	54.4	53.9	54.9
Housing Starts (b)	1.272	1.137	1.203	1.267	1.268	1.235	1.212	1.377	1.274	1.340	1.371	1.587
Housing Permits (b)	1.316	1.305	1.327	1.330	1.338	1.273	1.366	1.471	1.437	1.503	1.510	1.457
New Home Sales (1-family) (h)	637	665	700	664	600	726	661	706	726	706	696	731
Construction Expenditures (a)	1.4	0.5	0.8	0.6	-0.7	-0.9	0.5	1.1	0.7	0.4	1.6	0.4
Consumer Price Index (nsa, d)	1.6	1.5	1.9	2.0	1.8	1.6	1.8	1.7	1.7	1.8	2.1	2.3
CPI ex. Food and Energy (nsa, d)	2.2	2.1	2.0	2.1	2.0	2.1	2.2	2.4	2.4	2.3	2.3	2.3
Producer Price Index (nsa, d)	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.4
Durable Goods Orders (a)	0.2	-3.3	4.0	-4.7	-1.5	0.1	2.5	0.5	-0.9	-0.1	-2.6	2.8
Leading Economic Indicators (a)	0.0	0.2	0.2	0.1	0.0	0.0	0.4	-0.2	-0.2	-0.2	0.2	-0.2
Balance of Trade & Services (f)	-53.8	-51.3	-52.7	-51.3	-54.8	-54.3	-53.2	-53.9	-51.3	-47.4	-43.8	-48.6
Federal Funds Rate (%)	2.40	2.40	2.41	2.42	2.39	2.38	2.40	2.13	2.04	1.83	1.55	1.55
3-Mo. Treasury Bill Rate (%)	2.42	2.44	2.45	2.43	2.40	2.22	2.15	1.99	1.93	1.68	1.57	1.57
10-Year Treasury Note Yield (%)	2.71	2.68	2.57	2.53	2.40	2.07	2.06	1.63	1.70	1.71	1.81	1.86

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level; (h) thousands. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
June 1 ISM Manufacturing (May) IHS Markit Mfg PMI (May) Construction (Apr) NABE Outlook (Q2)	**2**	**3** ADP Employment Report(May) MSIO (Apr) ISM Nonmanufacturing (May) IHS Markit Services PMI(May) EIA Crude Oil Stocks Mortgage Applications	**4** Productivity & Costs (Q1) International Trade (Apr) Public Debt (May) Challenger Employment Report (May) Weekly Jobless Claims Weekly Money Supply	**5** Employment Situation (May) Consumer Credit (Apr)
8 QFR (Q1) Treasury Auction Allotments (May**)**	**9** JOLTS (Apr) Wholesale Trade (Apr) Manpower Survey (Q3) NFIB (May) Kansas City Financial Stress Index (May) FOMC Meeting	**10** CPI (May) Monthly Treasury (May) Kansas City Fed Labor Market Conditions Indicators (May) FOMC Meeting EIA Crude Oil Stocks Mortgage Applications	**11** PPI (May) QSS (Q1) Weekly Jobless Claims Weekly Money Supply	**12** Import & Export Prices (May) Consumer Sentiment (Jun, Preliminary) Livingston Survey (Jun)
15 Empire State Mfg Survey (Jun) TIC Data (Apr)	**16** Advance Retail Sales (May) IP (May) MTIS (Apr)	**17** New Residential Construction (May) EIA Crude Oil Stocks Mortgage Applications	**18** ECEC (Q1) Philadelphia Fed Mfg Business Outlook Survey (Jun) Composite Indexes (May Weekly Jobless Claims Weekly Money Supply)	**19** Regional Retail Sales (May) International Transactions(Q1)
22 Existing Home Sales (May) Treasury Auction Allotments (Jun) Chicago Fed National Activity Index (May)	23 New Residential Sales (May) Final Building Permits (May) Philadelphia Fed Nonmfg Bus Outlook Survey (Jun) Richmond Fed Mfg & Service Sector Surveys (Jun) Steel Imports (May, Prelim) IHS Markit Flash US Composite PMI (Jun)	**24** FHFA HPI (Apr) EIA Crude Oil Stocks Mortgage Applications	**25** Adv Trade & Inventories(May) GDP (Q1, 3rd Estimate) Advance Durable Goods (May) Kansas City Fed Manufacturing Survey (Jun) Weekly Jobless Claims Weekly Money Supply)	**26** Personal Income (May) Dallas Fed Trimmed-Mean PCE (May) Underlying NIPA Tables (May) Consumer Sentiment (Jun, Final) FRB Philadelphia Coincident Economic Activity Index (May)
29 Texas Manufacturing Outlook Survey (Jun) Pending Home Sales (May)	30 IIP (Q1) Case-Shiller HPI (Apr) Consumer Confidence (Jun Agricultural Prices (May) Chicago PMI (Jun) Texas Service Sector Outlook Survey (Jun)	**July 1** ADP Employment Report (Jun) Construction (May) ISM Manufacturing (Jun) IHS Markit Mfg PMI (Jun) Challenger Employment Report (Jun) EIA Crude Oil Stocks Mortgage Applications	**2** Employment Situation (Jun) Intl Trade/Supplement (May) Manufacturers' Shipments, Inventories & Orders (May) Weekly Jobless Claims Weekly Money Supply)	3
6 GDP by Industry (Q1) ISM Nonmanufacturing (Jun) IHS Markit Services PMI(Jun)	**7** JOLTS (May) Public Debt (Jun)	**8** Consumer Credit (May) Kansas City Fed Labor Market Conditions Indicators (Jun) EIA Crude Oil Stocks Mortgage Applications	**9** Wholesale Trade (May) Transportation Services Index (May) Kansas City Financial Stress Index (Jun) Weekly Jobless Claims Weekly Money Supply)	**10** Producer Prices (Jun)

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NEW

REGULATORY

FINANCE

Roger A. Morin, PhD

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Chapter 6
Alternative Asset Pricing Models

6.1 Empirical Validity of the CAPM

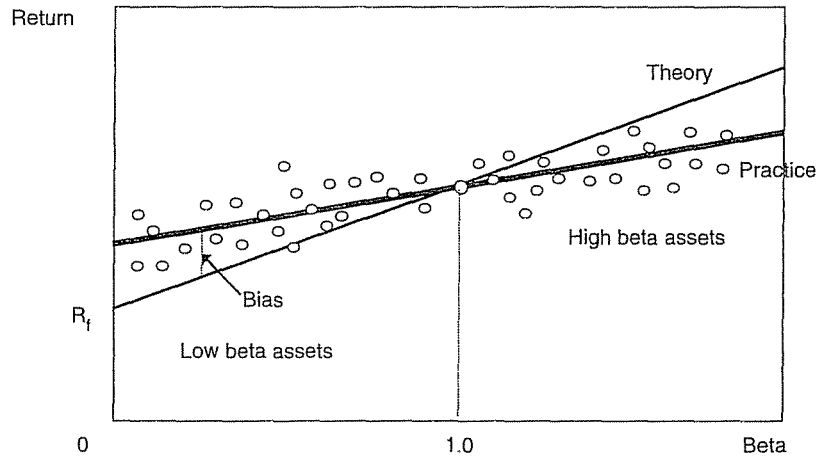
The last chapter showed that the practical difficulties of implementing the CAPM approach are surmountable. Conceptual and empirical problems remain, however.

At the conceptual level, the CAPM has been submitted to criticisms by academicians and practitioners. Contrary to the core assumption of the CAPM, investors may choose not to diversify, and bear company-specific risk if abnormal returns are expected. A substantial percentage of individual investors are indeed inadequately diversified. Short selling is somewhat restricted, in violation of CAPM assumptions. Factors other than market risk (beta) may also influence investor behavior, such as taxation, firm size, and restrictions on borrowing.

At the empirical level, there have been countless tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as predicted by the CAPM. With few exceptions, the empirical studies agree that the implied intercept term exceeds the risk-free rate and the slope term is less than predicted by the CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is shown pictorially in Figure 6-1. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. Brealey, Myers, and Allen (2006), among many others,[1] provide recent empirical evidence very similar to the relationship depicted in Figure 6-1. This is one of the most

[1] For a summary of the empirical evidence on the CAPM, see Jensen (1972) and Ross (1978). The major empirical tests of the CAPM were published by Friend and Blume (1975), Black, Jensen, and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973), Blume and Husic (1973), Fama and Macbeth (1972), Basu (1977), Reinganum (1981B), Litzenberger and Ramaswamy (1979), Banz (1981), Gibbons (1982), Stambaugh (1982), Shanken (1985), Black (1993), and Brealey, Myers, and Allen (2006). Evidence in the Canadian context is available in Morin (1980, 1981).

FIGURE 6-1
PREDICTED VS. OBSERVED CAPM RETURN ESTIMATES



well-known results in finance. This result is particularly pertinent for public utilities whose betas are typically less than 1.00. Based on the evidence, as shown in Figure 6-1, a CAPM-based estimate of the cost of capital underestimates the return required from such securities.

The empirical evidence also demonstrates that the SML is highly unstable over short periods and differs significantly from the long-run relationship. This evidence underscores the potential for error in cost of capital estimates that apply the CAPM using historical data over short time periods. The evidence[2] also shows that the addition of specific company risk, as measured by standard deviation, adds explanatory power to the risk-return relationship.

In short, the currently available empirical evidence indicates that the simple version of the CAPM does not provide a perfectly accurate description of the process determining security returns. Explanations for this shortcoming include some or all of the following:

1. The CAPM excludes other important variables that are important in determining security returns, such as size, skewness, and taxes.
2. The market index used in the tests excludes important classes of securities, such as bonds, mortgages, and business investments. There is a further argument that the CAPM can never be really tested and that such a test is infeasible. This is because the market index proxy used

[2] See Friend, Westerfield, and Granito (1978) and Morin (1980).

The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \qquad (6\text{-}5)$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return $= 0.0829 + 0.0520\,\beta$ is between 0.25 and 0.30. If $x = 0.25$, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$K = 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%)$$
$$= 5.0\% + 1.8\% + 4.2\%$$
$$= 11.0\%$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

The capital asset pricing model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often the only asset pricing model taught in these courses.[1]

The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor—poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive "market portfolio" that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it

[1] Although every asset pricing model is a capital asset pricing model, the finance profession reserves the acronym CAPM for the specific model of Sharpe (1964), Lintner (1965) and Black (1972) discussed here. Thus, throughout the paper we refer to the Sharpe-Lintner-Black model as the CAPM.

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legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

We begin by outlining the logic of the CAPM, focusing on its predictions about risk and expected return. We then review the history of empirical work and what it says about shortcomings of the CAPM that pose challenges to be explained by alternative models.

The Logic of the CAPM

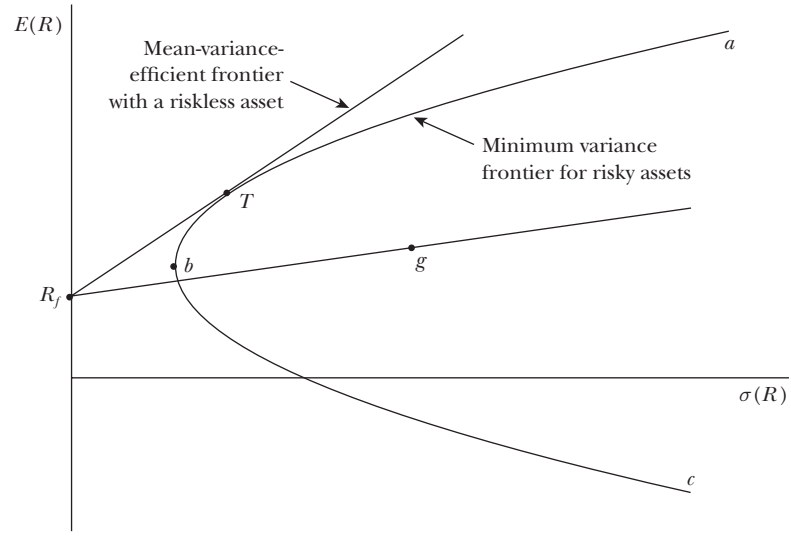
The CAPM builds on the model of portfolio choice developed by Harry Markowitz (1959). In Markowitz's model, an investor selects a portfolio at time $t - 1$ that produces a stochastic return at t. The model assumes investors are risk averse and, when choosing among portfolios, they care only about the mean and variance of their one-period investment return. As a result, investors choose "mean-variance-efficient" portfolios, in the sense that the portfolios 1) minimize the variance of portfolio return, given expected return, and 2) maximize expected return, given variance. Thus, the Markowitz approach is often called a "mean-variance model."

The portfolio model provides an algebraic condition on asset weights in mean-variance-efficient portfolios. The CAPM turns this algebraic statement into a testable prediction about the relation between risk and expected return by identifying a portfolio that must be efficient if asset prices are to clear the market of all assets.

Sharpe (1964) and Lintner (1965) add two key assumptions to the Markowitz model to identify a portfolio that must be mean-variance-efficient. The first assumption is *complete agreement*: given market clearing asset prices at $t - 1$, investors agree on the joint distribution of asset returns from $t - 1$ to t. And this distribution is the true one—that is, it is the distribution from which the returns we use to test the model are drawn. The second assumption is that there is *borrowing and lending at a risk-free rate*, which is the same for all investors and does not depend on the amount borrowed or lent.

Figure 1 describes portfolio opportunities and tells the CAPM story. The horizontal axis shows portfolio risk, measured by the standard deviation of portfolio return; the vertical axis shows expected return. The curve *abc*, which is called the minimum variance frontier, traces combinations of expected return and risk for portfolios of risky assets that minimize return variance at different levels of expected return. (These portfolios do not include risk-free borrowing and lending.) The tradeoff between risk and expected return for minimum variance portfolios is apparent. For example, an investor who wants a high expected return, perhaps at point a, must accept high volatility. At point T, the investor can have an interme-

Figure 1
Investment Opportunities



diate expected return with lower volatility. If there is no risk-free borrowing or lending, only portfolios above *b* along *abc* are mean-variance-efficient, since these portfolios also maximize expected return, given their return variances.

Adding risk-free borrowing and lending turns the efficient set into a straight line. Consider a portfolio that invests the proportion x of portfolio funds in a risk-free security and $1 - x$ in some portfolio g. If all funds are invested in the risk-free security—that is, they are loaned at the risk-free rate of interest—the result is the point R_f in Figure 1, a portfolio with zero variance and a risk-free rate of return. Combinations of risk-free lending and positive investment in g plot on the straight line between R_f and g. Points to the right of g on the line represent borrowing at the risk-free rate, with the proceeds from the borrowing used to increase investment in portfolio g. In short, portfolios that combine risk-free lending or borrowing with some risky portfolio g plot along a straight line from R_f through g in Figure 1.[2]

[2] Formally, the return, expected return and standard deviation of return on portfolios of the risk-free asset f and a risky portfolio g vary with x, the proportion of portfolio funds invested in f, as

$$R_p = xR_f + (1 - x)R_g,$$

$$E(R_p) = xR_f + (1 - x)E(R_g),$$

$$\sigma(R_p) = (1 - x)\sigma(R_g),\ x \leq 1.0,$$

which together imply that the portfolios plot along the line from R_f through g in Figure 1.

To obtain the mean-variance-efficient portfolios available with risk-free borrowing and lending, one swings a line from R_f in Figure 1 up and to the left as far as possible, to the tangency portfolio T. We can then see that all efficient portfolios are combinations of the risk-free asset (either risk-free borrowing or lending) and a single risky tangency portfolio, T. This key result is Tobin's (1958) "separation theorem."

The punch line of the CAPM is now straightforward. With complete agreement about distributions of returns, all investors see the same opportunity set (Figure 1), and they combine the same risky tangency portfolio T with risk-free lending or borrowing. Since all investors hold the same portfolio T of risky assets, it must be the value-weight market portfolio of risky assets. Specifically, each risky asset's weight in the tangency portfolio, which we now call M (for the "market"), must be the total market value of all outstanding units of the asset divided by the total market value of all risky assets. In addition, the risk-free rate must be set (along with the prices of risky assets) to clear the market for risk-free borrowing and lending.

In short, the CAPM assumptions imply that the market portfolio M must be on the minimum variance frontier if the asset market is to clear. This means that the algebraic relation that holds for any minimum variance portfolio must hold for the market portfolio. Specifically, if there are N risky assets,

$$\text{(Minimum Variance Condition for } M) \quad E(R_i) = E(R_{ZM}) + [E(R_M) - E(R_{ZM})]\beta_{iM},\ i = 1, \ldots, N.$$

In this equation, $E(R_i)$ is the expected return on asset i, and β_{iM}, the market beta of asset i, is the covariance of its return with the market return divided by the variance of the market return,

$$\text{(Market Beta)} \quad \beta_{iM} = \frac{\text{cov}(R_i, R_M)}{\sigma^2(R_M)}.$$

The first term on the right-hand side of the minimum variance condition, $E(R_{ZM})$, is the expected return on assets that have market betas equal to zero, which means their returns are uncorrelated with the market return. The second term is a risk premium—the market beta of asset i, β_{iM}, times the premium per unit of beta, which is the expected market return, $E(R_M)$, minus $E(R_{ZM})$.

Since the market beta of asset i is also the slope in the regression of its return on the market return, a common (and correct) interpretation of beta is that it measures the sensitivity of the asset's return to variation in the market return. But there is another interpretation of beta more in line with the spirit of the portfolio model that underlies the CAPM. The risk of the market portfolio, as measured by the variance of its return (the denominator of β_{iM}), is a weighted average of the covariance risks of the assets in M (the numerators of β_{iM} for different assets).

Thus, β_{iM} is the covariance risk of asset i in M measured relative to the average covariance risk of assets, which is just the variance of the market return.[3] In economic terms, β_{iM} is proportional to the risk each dollar invested in asset i contributes to the market portfolio.

The last step in the development of the Sharpe-Lintner model is to use the assumption of risk-free borrowing and lending to nail down $E(R_{ZM})$, the expected return on zero-beta assets. A risky asset's return is uncorrelated with the market return—its beta is zero—when the average of the asset's covariances with the returns on other assets just offsets the variance of the asset's return. Such a risky asset is riskless in the market portfolio in the sense that it contributes nothing to the variance of the market return.

When there is risk-free borrowing and lending, the expected return on assets that are uncorrelated with the market return, $E(R_{ZM})$, must equal the risk-free rate, R_f. The relation between expected return and beta then becomes the familiar Sharpe-Lintner CAPM equation,

$$\text{(Sharpe-Lintner CAPM)} \quad E(R_i) = R_f + [E(R_M) - R_f]\beta_{iM},\ i = 1, \ldots, N.$$

In words, the expected return on any asset i is the risk-free interest rate, R_f, plus a risk premium, which is the asset's market beta, β_{iM}, times the premium per unit of beta risk, $E(R_M) - R_f$.

Unrestricted risk-free borrowing and lending is an unrealistic assumption. Fischer Black (1972) develops a version of the CAPM without risk-free borrowing or lending. He shows that the CAPM's key result—that the market portfolio is mean-variance-efficient—can be obtained by instead allowing unrestricted short sales of risky assets. In brief, back in Figure 1, if there is no risk-free asset, investors select portfolios from along the mean-variance-efficient frontier from a to b. Market clearing prices imply that when one weights the efficient portfolios chosen by investors by their (positive) shares of aggregate invested wealth, the resulting portfolio is the market portfolio. The market portfolio is thus a portfolio of the efficient portfolios chosen by investors. With unrestricted short selling of risky assets, portfolios made up of efficient portfolios are themselves efficient. Thus, the market portfolio is efficient, which means that the minimum variance condition for M given above holds, and it is the expected return-risk relation of the Black CAPM.

The relations between expected return and market beta of the Black and Sharpe-Lintner versions of the CAPM differ only in terms of what each says about $E(R_{ZM})$, the expected return on assets uncorrelated with the market. The Black version says only that $E(R_{ZM})$ must be less than the expected market return, so the

[3] Formally, if x_{iM} is the weight of asset i in the market portfolio, then the variance of the portfolio's return is

$$\sigma^2(R_M) = Cov(R_M, R_M) = Cov\left(\sum_{i=1}^{N} x_{iM}R_i, R_M\right) = \sum_{i=1}^{N} x_{iM}Cov(R_i, R_M).$$

premium for beta is positive. In contrast, in the Sharpe-Lintner version of the model, $E(R_{ZM})$ must be the risk-free interest rate, R_f, and the premium per unit of beta risk is $E(R_M) - R_f$.

The assumption that short selling is unrestricted is as unrealistic as unrestricted risk-free borrowing and lending. If there is no risk-free asset and short sales of risky assets are not allowed, mean-variance investors still choose efficient portfolios—points above *b* on the *abc* curve in Figure 1. But when there is no short selling of risky assets and no risk-free asset, the algebra of portfolio efficiency says that portfolios made up of efficient portfolios are not typically efficient. This means that the market portfolio, which is a portfolio of the efficient portfolios chosen by investors, is not typically efficient. And the CAPM relation between expected return and market beta is lost. This does not rule out predictions about expected return and betas with respect to other efficient portfolios—if theory can specify portfolios that must be efficient if the market is to clear. But so far this has proven impossible.

In short, the familiar CAPM equation relating expected asset returns to their market betas is just an application to the market portfolio of the relation between expected return and portfolio beta that holds in any mean-variance-efficient portfolio. The efficiency of the market portfolio is based on many unrealistic assumptions, including complete agreement and either unrestricted risk-free borrowing and lending or unrestricted short selling of risky assets. But all interesting models involve unrealistic simplifications, which is why they must be tested against data.

Early Empirical Tests

Tests of the CAPM are based on three implications of the relation between expected return and market beta implied by the model. First, expected returns on all assets are linearly related to their betas, and no other variable has marginal explanatory power. Second, the beta premium is positive, meaning that the expected return on the market portfolio exceeds the expected return on assets whose returns are uncorrelated with the market return. Third, in the Sharpe-Lintner version of the model, assets uncorrelated with the market have expected returns equal to the risk-free interest rate, and the beta premium is the expected market return minus the risk-free rate. Most tests of these predictions use either cross-section or time-series regressions. Both approaches date to early tests of the model.

Tests on Risk Premiums

The early cross-section regression tests focus on the Sharpe-Lintner model's predictions about the intercept and slope in the relation between expected return and market beta. The approach is to regress a cross-section of average asset returns on estimates of asset betas. The model predicts that the intercept in these regressions is the risk-free interest rate, R_f, and the coefficient on beta is the expected return on the market in excess of the risk-free rate, $E(R_M) - R_f$.

Two problems in these tests quickly became apparent. First, estimates of beta

for individual assets are imprecise, creating a measurement error problem when they are used to explain average returns. Second, the regression residuals have common sources of variation, such as industry effects in average returns. Positive correlation in the residuals produces downward bias in the usual ordinary least squares estimates of the standard errors of the cross-section regression slopes.

To improve the precision of estimated betas, researchers such as Blume (1970), Friend and Blume (1970) and Black, Jensen and Scholes (1972) work with portfolios, rather than individual securities. Since expected returns and market betas combine in the same way in portfolios, if the CAPM explains security returns it also explains portfolio returns.[4] Estimates of beta for diversified portfolios are more precise than estimates for individual securities. Thus, using portfolios in cross-section regressions of average returns on betas reduces the critical errors in variables problem. Grouping, however, shrinks the range of betas and reduces statistical power. To mitigate this problem, researchers sort securities on beta when forming portfolios; the first portfolio contains securities with the lowest betas, and so on, up to the last portfolio with the highest beta assets. This sorting procedure is now standard in empirical tests.

Fama and MacBeth (1973) propose a method for addressing the inference problem caused by correlation of the residuals in cross-section regressions. Instead of estimating a single cross-section regression of average monthly returns on betas, they estimate month-by-month cross-section regressions of monthly returns on betas. The times-series means of the monthly slopes and intercepts, along with the standard errors of the means, are then used to test whether the average premium for beta is positive and whether the average return on assets uncorrelated with the market is equal to the average risk-free interest rate. In this approach, the standard errors of the average intercept and slope are determined by the month-to-month variation in the regression coefficients, which fully captures the effects of residual correlation on variation in the regression coefficients, but sidesteps the problem of actually estimating the correlations. The residual correlations are, in effect, captured via repeated sampling of the regression coefficients. This approach also becomes standard in the literature.

Jensen (1968) was the first to note that the Sharpe-Lintner version of the

[4] Formally, if x_{ip}, $i = 1, \ldots, N$, are the weights for assets in some portfolio p, the expected return and market beta for the portfolio are related to the expected returns and betas of assets as

$$E(R_p) = \sum_{i=1}^{N} x_{ip}E(R_i), \text{ and } \beta_{pM} = \sum_{i=1}^{N} x_{ip}\beta_{pM}.$$

Thus, the CAPM relation between expected return and beta,

$$E(R_i) = E(R_f) + [E(R_M) - E(R_f)]\beta_{iM},$$

holds when asset i is a portfolio, as well as when i is an individual security.

relation between expected return and market beta also implies a time-series regression test. The Sharpe-Lintner CAPM says that the expected value of an asset's excess return (the asset's return minus the risk-free interest rate, $R_{it} - R_{ft}$) is completely explained by its expected CAPM risk premium (its beta times the expected value of $R_{Mt} - R_{ft}$). This implies that "Jensen's alpha," the intercept term in the time-series regression,

$$\text{(Time-Series Regression)} \quad R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \varepsilon_{it},$$

is zero for each asset.

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat." Recall that, in cross-section regressions, the Sharpe-Lintner model predicts that the intercept is the risk-free rate and the coefficient on beta is the expected market return in excess of the risk-free rate, $E(R_M) - R_f$. The regressions consistently find that the intercept is greater than the average risk-free rate (typically proxied as the return on a one-month Treasury bill), and the coefficient on beta is less than the average excess market return (proxied as the average return on a portfolio of U.S. common stocks minus the Treasury bill rate). This is true in the early tests, such as Douglas (1968), Black, Jensen and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973) and Fama and MacBeth (1973), as well as in more recent cross-section regression tests, like Fama and French (1992).

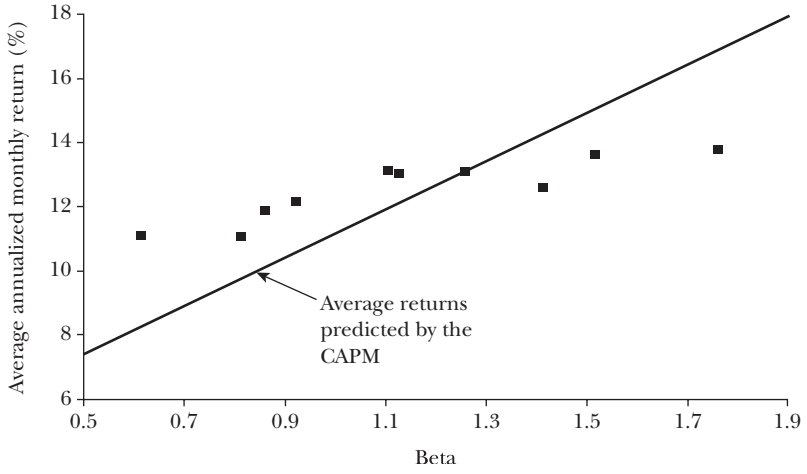
The evidence that the relation between beta and average return is too flat is confirmed in time-series tests, such as Friend and Blume (1970), Black, Jensen and Scholes (1972) and Stambaugh (1982). The intercepts in time-series regressions of excess asset returns on the excess market return are positive for assets with low betas and negative for assets with high betas.

Figure 2 provides an updated example of the evidence. In December of each year, we estimate a preranking beta for every NYSE (1928–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stock in the CRSP (Center for Research in Security Prices of the University of Chicago) database, using two to five years (as available) of prior monthly returns.[5] We then form ten value-weight portfolios based on these preranking betas and compute their returns for the next twelve months. We repeat this process for each year from 1928 to 2003. The result is 912 monthly returns on ten beta-sorted portfolios. Figure 2 plots each portfolio's average return against its postranking beta, estimated by regressing its monthly returns for 1928–2003 on the return on the CRSP value-weight portfolio of U.S. common stocks.

The Sharpe-Lintner CAPM predicts that the portfolios plot along a straight

[5] To be included in the sample for year t, a security must have market equity data (price times shares outstanding) for December of $t - 1$, and CRSP must classify it as ordinary common equity. Thus, we exclude securities such as American Depository Receipts (ADRs) and Real Estate Investment Trusts (REITs).

Figure 2
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



line, with an intercept equal to the risk-free rate, R_f, and a slope equal to the expected excess return on the market, $E(R_M) - R_f$. We use the average one-month Treasury bill rate and the average excess CRSP market return for 1928–2003 to estimate the predicted line in Figure 2. Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Lintner CAPM predicts. The returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.

Although the observed premium per unit of beta is lower than the Sharpe-Lintner model predicts, the relation between average return and beta in Figure 2 is roughly linear. This is consistent with the Black version of the CAPM, which predicts only that the beta premium is positive. Even this less restrictive model, however, eventually succumbs to the data.

Testing Whether Market Betas Explain Expected Returns

The Sharpe-Lintner and Black versions of the CAPM share the prediction that the market portfolio is mean-variance-efficient. This implies that differences in expected return across securities and portfolios are entirely explained by differences in market beta; other variables should add nothing to the explanation of expected return. This prediction plays a prominent role in tests of the CAPM. In the early work, the weapon of choice is cross-section regressions.

In the framework of Fama and MacBeth (1973), one simply adds predetermined explanatory variables to the month-by-month cross-section regressions of

returns on beta. If all differences in expected return are explained by beta, the average slopes on the additional variables should not be reliably different from zero. Clearly, the trick in the cross-section regression approach is to choose specific additional variables likely to expose any problems of the CAPM prediction that, because the market portfolio is efficient, market betas suffice to explain expected asset returns.

For example, in Fama and MacBeth (1973) the additional variables are squared market betas (to test the prediction that the relation between expected return and beta is linear) and residual variances from regressions of returns on the market return (to test the prediction that market beta is the only measure of risk needed to explain expected returns). These variables do not add to the explanation of average returns provided by beta. Thus, the results of Fama and MacBeth (1973) are consistent with the hypothesis that their market proxy—an equal-weight portfolio of NYSE stocks—is on the minimum variance frontier.

The hypothesis that market betas completely explain expected returns can also be tested using time-series regressions. In the time-series regression described above (the excess return on asset i regressed on the excess market return), the intercept is the difference between the asset's average excess return and the excess return predicted by the Sharpe-Lintner model, that is, beta times the average excess market return. If the model holds, there is no way to group assets into portfolios whose intercepts are reliably different from zero. For example, the intercepts for a portfolio of stocks with high ratios of earnings to price and a portfolio of stocks with low earning-price ratios should both be zero. Thus, to test the hypothesis that market betas suffice to explain expected returns, one estimates the time-series regression for a set of assets (or portfolios) and then jointly tests the vector of regression intercepts against zero. The trick in this approach is to choose the left-hand-side assets (or portfolios) in a way likely to expose any shortcoming of the CAPM prediction that market betas suffice to explain expected asset returns.

In early applications, researchers use a variety of tests to determine whether the intercepts in a set of time-series regressions are all zero. The tests have the same asymptotic properties, but there is controversy about which has the best small sample properties. Gibbons, Ross and Shanken (1989) settle the debate by providing an F-test on the intercepts that has exact small-sample properties. They also show that the test has a simple economic interpretation. In effect, the test constructs a candidate for the tangency portfolio T in Figure 1 by optimally combining the market proxy and the left-hand-side assets of the time-series regressions. The estimator then tests whether the efficient set provided by the combination of this tangency portfolio and the risk-free asset is reliably superior to the one obtained by combining the risk-free asset with the market proxy alone. In other words, the Gibbons, Ross and Shanken statistic tests whether the market proxy is the tangency portfolio in the set of portfolios that can be constructed by combining the market portfolio with the specific assets used as dependent variables in the time-series regressions.

Enlightened by this insight of Gibbons, Ross and Shanken (1989), one can see

a similar interpretation of the cross-section regression test of whether market betas suffice to explain expected returns. In this case, the test is whether the additional explanatory variables in a cross-section regression identify patterns in the returns on the left-hand-side assets that are not explained by the assets' market betas. This amounts to testing whether the market proxy is on the minimum variance frontier that can be constructed using the market proxy and the left-hand-side assets included in the tests.

An important lesson from this discussion is that time-series and cross-section regressions do not, strictly speaking, test the CAPM. What is literally tested is whether a specific proxy for the market portfolio (typically a portfolio of U.S. common stocks) is efficient in the set of portfolios that can be constructed from it and the left-hand-side assets used in the test. One might conclude from this that the CAPM has never been tested, and prospects for testing it are not good because 1) the set of left-hand-side assets does not include all marketable assets, and 2) data for the true market portfolio of all assets are likely beyond reach (Roll, 1977; more on this later). But this criticism can be leveled at tests of any economic model when the tests are less than exhaustive or when they use proxies for the variables called for by the model.

The bottom line from the early cross-section regression tests of the CAPM, such as Fama and MacBeth (1973), and the early time-series regression tests, like Gibbons (1982) and Stambaugh (1982), is that standard market proxies seem to be on the minimum variance frontier. That is, the central predictions of the Black version of the CAPM, that market betas suffice to explain expected returns and that the risk premium for beta is positive, seem to hold. But the more specific prediction of the Sharpe-Lintner CAPM that the premium per unit of beta is the expected market return minus the risk-free interest rate is consistently rejected.

The success of the Black version of the CAPM in early tests produced a consensus that the model is a good description of expected returns. These early results, coupled with the model's simplicity and intuitive appeal, pushed the CAPM to the forefront of finance.

Recent Tests

Starting in the late 1970s, empirical work appears that challenges even the Black version of the CAPM. Specifically, evidence mounts that much of the variation in expected return is unrelated to market beta.

The first blow is Basu's (1977) evidence that when common stocks are sorted on earnings-price ratios, future returns on high E/P stocks are higher than predicted by the CAPM. Banz (1981) documents a size effect: when stocks are sorted on market capitalization (price times shares outstanding), average returns on small stocks are higher than predicted by the CAPM. Bhandari (1988) finds that high debt-equity ratios (book value of debt over the market value of equity, a measure of leverage) are associated with returns that are too high relative to their market betas.

Finally, Statman (1980) and Rosenberg, Reid and Lanstein (1985) document that stocks with high book-to-market equity ratios (B/M, the ratio of the book value of a common stock to its market value) have high average returns that are not captured by their betas.

There is a theme in the contradictions of the CAPM summarized above. Ratios involving stock prices have information about expected returns missed by market betas. On reflection, this is not surprising. A stock's price depends not only on the expected cash flows it will provide, but also on the expected returns that discount expected cash flows back to the present. Thus, in principle, the cross-section of prices has information about the cross-section of expected returns. (A high expected return implies a high discount rate and a low price.) The cross-section of stock prices is, however, arbitrarily affected by differences in scale (or units). But with a judicious choice of scaling variable X, the ratio X/P can reveal differences in the cross-section of expected stock returns. Such ratios are thus prime candidates to expose shortcomings of asset pricing models—in the case of the CAPM, shortcomings of the prediction that market betas suffice to explain expected returns (Ball, 1978). The contradictions of the CAPM summarized above suggest that earnings-price, debt-equity and book-to-market ratios indeed play this role.

Fama and French (1992) update and synthesize the evidence on the empirical failures of the CAPM. Using the cross-section regression approach, they confirm that size, earnings-price, debt-equity and book-to-market ratios add to the explanation of expected stock returns provided by market beta. Fama and French (1996) reach the same conclusion using the time-series regression approach applied to portfolios of stocks sorted on price ratios. They also find that different price ratios have much the same information about expected returns. This is not surprising given that price is the common driving force in the price ratios, and the numerators are just scaling variables used to extract the information in price about expected returns.

Fama and French (1992) also confirm the evidence (Reinganum, 1981; Stambaugh, 1982; Lakonishok and Shapiro, 1986) that the relation between average return and beta for common stocks is even flatter after the sample periods used in the early empirical work on the CAPM. The estimate of the beta premium is, however, clouded by statistical uncertainty (a large standard error). Kothari, Shanken and Sloan (1995) try to resuscitate the Sharpe-Lintner CAPM by arguing that the weak relation between average return and beta is just a chance result. But the strong evidence that other variables capture variation in expected return missed by beta makes this argument irrelevant. If betas do not suffice to explain expected returns, the market portfolio is not efficient, and the CAPM is dead in its tracks. Evidence on the size of the market premium can neither save the model nor further doom it.

The synthesis of the evidence on the empirical problems of the CAPM provided by Fama and French (1992) serves as a catalyst, marking the point when it is generally acknowledged that the CAPM has potentially fatal problems. Research then turns to explanations.

One possibility is that the CAPM's problems are spurious, the result of data dredging—publication-hungry researchers scouring the data and unearthing contradictions that occur in specific samples as a result of chance. A standard response to this concern is to test for similar findings in other samples. Chan, Hamao and Lakonishok (1991) find a strong relation between book-to-market equity (B/M) and average return for Japanese stocks. Capaul, Rowley and Sharpe (1993) observe a similar B/M effect in four European stock markets and in Japan. Fama and French (1998) find that the price ratios that produce problems for the CAPM in U.S. data show up in the same way in the stock returns of twelve non-U.S. major markets, and they are present in emerging market returns. This evidence suggests that the contradictions of the CAPM associated with price ratios are not sample specific.

Explanations: Irrational Pricing or Risk

Among those who conclude that the empirical failures of the CAPM are fatal, two stories emerge. On one side are the behavioralists. Their view is based on evidence that stocks with high ratios of book value to market price are typically firms that have fallen on bad times, while low B/M is associated with growth firms (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1995). The behavioralists argue that sorting firms on book-to-market ratios exposes investor overreaction to good and bad times. Investors overextrapolate past performance, resulting in stock prices that are too high for growth (low B/M) firms and too low for distressed (high B/M, so-called value) firms. When the overreaction is eventually corrected, the result is high returns for value stocks and low returns for growth stocks. Proponents of this view include DeBondt and Thaler (1987), Lakonishok, Shleifer and Vishny (1994) and Haugen (1995).

The second story for explaining the empirical contradictions of the CAPM is that they point to the need for a more complicated asset pricing model. The CAPM is based on many unrealistic assumptions. For example, the assumption that investors care only about the mean and variance of one-period portfolio returns is extreme. It is reasonable that investors also care about how their portfolio return covaries with labor income and future investment opportunities, so a portfolio's return variance misses important dimensions of risk. If so, market beta is not a complete description of an asset's risk, and we should not be surprised to find that differences in expected return are not completely explained by differences in beta. In this view, the search should turn to asset pricing models that do a better job explaining average returns.

Merton's (1973) intertemporal capital asset pricing model (ICAPM) is a natural extension of the CAPM. The ICAPM begins with a different assumption about investor objectives. In the CAPM, investors care only about the wealth their portfolio produces at the end of the current period. In the ICAPM, investors are concerned not only with their end-of-period payoff, but also with the opportunities

they will have to consume or invest the payoff. Thus, when choosing a portfolio at time $t - 1$, ICAPM investors consider how their wealth at t might vary with future *state variables*, including labor income, the prices of consumption goods and the nature of portfolio opportunities at t, and expectations about the labor income, consumption and investment opportunities to be available after t.

Like CAPM investors, ICAPM investors prefer high expected return and low return variance. But ICAPM investors are also concerned with the covariances of portfolio returns with state variables. As a result, optimal portfolios are "multifactor efficient," which means they have the largest possible expected returns, given their return variances and the covariances of their returns with the relevant state variables.

Fama (1996) shows that the ICAPM generalizes the logic of the CAPM. That is, if there is risk-free borrowing and lending or if short sales of risky assets are allowed, market clearing prices imply that the market portfolio is multifactor efficient. Moreover, multifactor efficiency implies a relation between expected return and beta risks, but it requires additional betas, along with a market beta, to explain expected returns.

An ideal implementation of the ICAPM would specify the state variables that affect expected returns. Fama and French (1993) take a more indirect approach, perhaps more in the spirit of Ross's (1976) arbitrage pricing theory. They argue that though size and book-to-market equity are not themselves state variables, the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas. In support of this claim, they show that the returns on the stocks of small firms covary more with one another than with returns on the stocks of large firms, and returns on high book-to-market (value) stocks covary more with one another than with returns on low book-to-market (growth) stocks. Fama and French (1995) show that there are similar size and book-to-market patterns in the covariation of fundamentals like earnings and sales.

Based on this evidence, Fama and French (1993, 1996) propose a three-factor model for expected returns,

$$\text{(Three-Factor Model)} \quad E(R_{it}) - R_{ft} = \beta_{iM}[E(R_{Mt}) - R_{ft}] + \beta_{is}E(SMB_t) + \beta_{ih}E(HML_t).$$

In this equation, SMB_t (small minus big) is the difference between the returns on diversified portfolios of small and big stocks, HML_t (high minus low) is the difference between the returns on diversified portfolios of high and low B/M stocks, and the betas are slopes in the multiple regression of $R_{it} - R_{ft}$ on $R_{Mt} - R_{ft}$, SMB_t and HML_t.

For perspective, the average value of the market premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, which is 3.5 standard errors from zero. The

average values of SMB_t, and HML_t are 3.6 percent and 5.0 percent per year, and they are 2.1 and 3.1 standard errors from zero. All three premiums are volatile, with annual standard deviations of 21.0 percent ($R_{Mt} - R_{ft}$), 14.6 percent (SMB_t) and 14.2 percent (HML_t) per year. Although the average values of the premiums are large, high volatility implies substantial uncertainty about the true expected premiums.

One implication of the expected return equation of the three-factor model is that the intercept α_i in the time-series regression,

$$R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \beta_{is}SMB_t + \beta_{ih}HML_t + \varepsilon_{it},$$

is zero for all assets i. Using this criterion, Fama and French (1993, 1996) find that the model captures much of the variation in average return for portfolios formed on size, book-to-market equity and other price ratios that cause problems for the CAPM. Fama and French (1998) show that an international version of the model performs better than an international CAPM in describing average returns on portfolios formed on scaled price variables for stocks in 13 major markets.

The three-factor model is now widely used in empirical research that requires a model of expected returns. Estimates of α_i from the time-series regression above are used to calibrate how rapidly stock prices respond to new information (for example, Loughran and Ritter, 1995; Mitchell and Stafford, 2000). They are also used to measure the special information of portfolio managers, for example, in Carhart's (1997) study of mutual fund performance. Among practitioners like Ibbotson Associates, the model is offered as an alternative to the CAPM for estimating the cost of equity capital.

From a theoretical perspective, the main shortcoming of the three-factor model is its empirical motivation. The small-minus-big (SMB) and high-minus-low (HML) explanatory returns are not motivated by predictions about state variables of concern to investors. Instead they are brute force constructs meant to capture the patterns uncovered by previous work on how average stock returns vary with size and the book-to-market equity ratio.

But this concern is not fatal. The ICAPM does not require that the additional portfolios used along with the market portfolio to explain expected returns "mimic" the relevant state variables. In both the ICAPM and the arbitrage pricing theory, it suffices that the additional portfolios are well diversified (in the terminology of Fama, 1996, they are multifactor minimum variance) and that they are sufficiently different from the market portfolio to capture covariation in returns and variation in expected returns missed by the market portfolio. Thus, adding diversified portfolios that capture covariation in returns and variation in average returns left unexplained by the market is in the spirit of both the ICAPM and the Ross's arbitrage pricing theory.

The behavioralists are not impressed by the evidence for a risk-based explanation of the failures of the CAPM. They typically concede that the three-factor model captures covariation in returns missed by the market return and that it picks

up much of the size and value effects in average returns left unexplained by the CAPM. But their view is that the average return premium associated with the model's book-to-market factor—which does the heavy lifting in the improvements to the CAPM—is itself the result of investor overreaction that happens to be correlated across firms in a way that just looks like a risk story. In short, in the behavioral view, the market tries to set CAPM prices, and violations of the CAPM are due to mispricing.

The conflict between the behavioral irrational pricing story and the rational risk story for the empirical failures of the CAPM leaves us at a timeworn impasse. Fama (1970) emphasizes that the hypothesis that prices properly reflect available information must be tested in the context of a model of expected returns, like the CAPM. Intuitively, to test whether prices are rational, one must take a stand on what the market is trying to do in setting prices—that is, what is risk and what is the relation between expected return and risk? When tests reject the CAPM, one cannot say whether the problem is its assumption that prices are rational (the behavioral view) or violations of other assumptions that are also necessary to produce the CAPM (our position).

Fortunately, for some applications, the way one uses the three-factor model does not depend on one's view about whether its average return premiums are the rational result of underlying state variable risks, the result of irrational investor behavior or sample specific results of chance. For example, when measuring the response of stock prices to new information or when evaluating the performance of managed portfolios, one wants to account for known patterns in returns and average returns for the period examined, whatever their source. Similarly, when estimating the cost of equity capital, one might be unconcerned with whether expected return premiums are rational or irrational since they are in either case part of the opportunity cost of equity capital (Stein, 1996). But the cost of capital is forward looking, so if the premiums are sample specific they are irrelevant.

The three-factor model is hardly a panacea. Its most serious problem is the momentum effect of Jegadeesh and Titman (1993). Stocks that do well relative to the market over the last three to twelve months tend to continue to do well for the next few months, and stocks that do poorly continue to do poorly. This momentum effect is distinct from the value effect captured by book-to-market equity and other price ratios. Moreover, the momentum effect is left unexplained by the three-factor model, as well as by the CAPM. Following Carhart (1997), one response is to add a momentum factor (the difference between the returns on diversified portfolios of short-term winners and losers) to the three-factor model. This step is again legitimate in applications where the goal is to abstract from known patterns in average returns to uncover information-specific or manager-specific effects. But since the momentum effect is short-lived, it is largely irrelevant for estimates of the cost of equity capital.

Another strand of research points to problems in both the three-factor model and the CAPM. Frankel and Lee (1998), Dechow, Hutton and Sloan (1999), Piotroski (2000) and others show that in portfolios formed on price ratios like

book-to-market equity, stocks with higher expected cash flows have higher average returns that are not captured by the three-factor model or the CAPM. The authors interpret their results as evidence that stock prices are irrational, in the sense that they do not reflect available information about expected profitability.

In truth, however, one can't tell whether the problem is bad pricing or a bad asset pricing model. A stock's price can always be expressed as the present value of expected future cash flows discounted at the expected return on the stock (Campbell and Shiller, 1989; Vuolteenaho, 2002). It follows that if two stocks have the same price, the one with higher expected cash flows must have a higher expected return. This holds true whether pricing is rational or irrational. Thus, when one observes a positive relation between expected cash flows and expected returns that is left unexplained by the CAPM or the three-factor model, one can't tell whether it is the result of irrational pricing or a misspecified asset pricing model.

The Market Proxy Problem

Roll (1977) argues that the CAPM has never been tested and probably never will be. The problem is that the market portfolio at the heart of the model is theoretically and empirically elusive. It is not theoretically clear which assets (for example, human capital) can legitimately be excluded from the market portfolio, and data availability substantially limits the assets that are included. As a result, tests of the CAPM are forced to use proxies for the market portfolio, in effect testing whether the proxies are on the minimum variance frontier. Roll argues that because the tests use proxies, not the true market portfolio, we learn nothing about the CAPM.

We are more pragmatic. The relation between expected return and market beta of the CAPM is just the minimum variance condition that holds in any efficient portfolio, applied to the market portfolio. Thus, if we can find a market proxy that is on the minimum variance frontier, it can be used to describe differences in expected returns, and we would be happy to use it for this purpose. The strong rejections of the CAPM described above, however, say that researchers have not uncovered a reasonable market proxy that is close to the minimum variance frontier. If researchers are constrained to reasonable proxies, we doubt they ever will.

Our pessimism is fueled by several empirical results. Stambaugh (1982) tests the CAPM using a range of market portfolios that include, in addition to U.S. common stocks, corporate and government bonds, preferred stocks, real estate and other consumer durables. He finds that tests of the CAPM are not sensitive to expanding the market proxy beyond common stocks, basically because the volatility of expanded market returns is dominated by the volatility of stock returns.

One need not be convinced by Stambaugh's (1982) results since his market proxies are limited to U.S. assets. If international capital markets are open and asset prices conform to an international version of the CAPM, the market portfolio

should include international assets. Fama and French (1998) find, however, that betas for a global stock market portfolio cannot explain the high average returns observed around the world on stocks with high book-to-market or high earnings-price ratios.

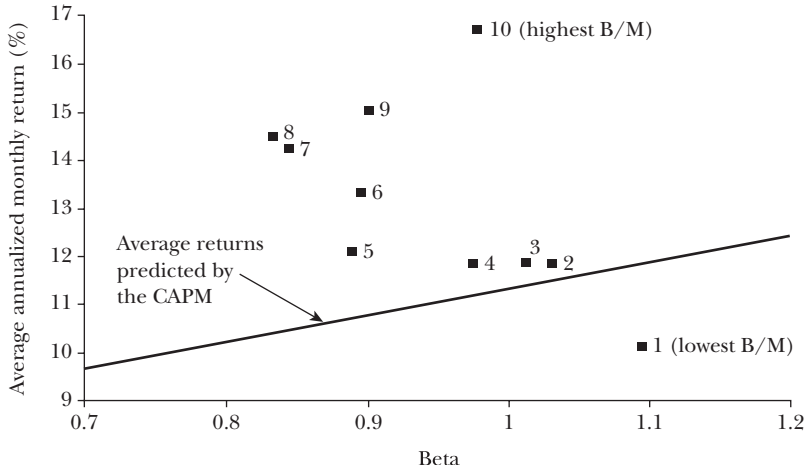
A major problem for the CAPM is that portfolios formed by sorting stocks on price ratios produce a wide range of average returns, but the average returns are not positively related to market betas (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1996, 1998). The problem is illustrated in Figure 3, which shows average returns and betas (calculated with respect to the CRSP value-weight portfolio of NYSE, AMEX and NASDAQ stocks) for July 1963 to December 2003 for ten portfolios of U.S. stocks formed annually on sorted values of the book-to-market equity ratio (B/M).[6]

Average returns on the B/M portfolios increase almost monotonically, from 10.1 percent per year for the lowest B/M group (portfolio 1) to an impressive 16.7 percent for the highest (portfolio 10). But the positive relation between beta and average return predicted by the CAPM is notably absent. For example, the portfolio with the lowest book-to-market ratio has the highest beta but the lowest average return. The estimated beta for the portfolio with the highest book-to-market ratio and the highest average return is only 0.98. With an average annualized value of the riskfree interest rate, R_f, of 5.8 percent and an average annualized market premium, $R_M - R_f$, of 11.3 percent, the Sharpe-Lintner CAPM predicts an average return of 11.8 percent for the lowest B/M portfolio and 11.2 percent for the highest, far from the observed values, 10.1 and 16.7 percent. For the Sharpe-Lintner model to "work" on these portfolios, their market betas must change dramatically, from 1.09 to 0.78 for the lowest B/M portfolio and from 0.98 to 1.98 for the highest. We judge it unlikely that alternative proxies for the market portfolio will produce betas and a market premium that can explain the average returns on these portfolios.

It is always possible that researchers will redeem the CAPM by finding a reasonable proxy for the market portfolio that is on the minimum variance frontier. We emphasize, however, that this possibility cannot be used to justify the way the CAPM is currently applied. The problem is that applications typically use the same

[6] Stock return data are from CRSP, and book equity data are from Compustat and the Moody's Industrials, Transportation, Utilities and Financials manuals. Stocks are allocated to ten portfolios at the end of June of each year t (1963 to 2003) using the ratio of book equity for the fiscal year ending in calendar year $t - 1$, divided by market equity at the end of December of $t - 1$. Book equity is the book value of stockholders' equity, plus balance sheet deferred taxes and investment tax credit (if available), minus the book value of preferred stock. Depending on availability, we use the redemption, liquidation or par value (in that order) to estimate the book value of preferred stock. Stockholders' equity is the value reported by Moody's or Compustat, if it is available. If not, we measure stockholders' equity as the book value of common equity plus the par value of preferred stock or the book value of assets minus total liabilities (in that order). The portfolios for year t include NYSE (1963–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stocks with positive book equity in $t - 1$ and market equity (from CRSP) for December of $t - 1$ and June of t. The portfolios exclude securities CRSP does not classify as ordinary common equity. The breakpoints for year t use only securities that are on the NYSE in June of year t.

Figure 3
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on B/M, 1963–2003



market proxies, like the value-weight portfolio of U.S. stocks, that lead to rejections of the model in empirical tests. The contradictions of the CAPM observed when such proxies are used in tests of the model show up as bad estimates of expected returns in applications; for example, estimates of the cost of equity capital that are too low (relative to historical average returns) for small stocks and for stocks with high book-to-market equity ratios. In short, if a market proxy does not work in tests of the CAPM, it does not work in applications.

Conclusions

The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success. In the early empirical work, the Black (1972) version of the model, which can accommodate a flatter tradeoff of average return for market beta, has some success. But in the late 1970s, research begins to uncover variables like size, various price ratios and momentum that add to the explanation of average returns provided by beta. The problems are serious enough to invalidate most applications of the CAPM.

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a

result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low.[7]

The CAPM is also often used to measure the performance of mutual funds and other managed portfolios. The approach, dating to Jensen (1968), is to estimate the CAPM time-series regression for a portfolio and use the intercept (Jensen's alpha) to measure abnormal performance. The problem is that, because of the empirical failings of the CAPM, even passively managed stock portfolios produce abnormal returns if their investment strategies involve tilts toward CAPM problems (Elton, Gruber, Das and Hlavka, 1993). For example, funds that concentrate on low beta stocks, small stocks or value stocks will tend to produce positive abnormal returns relative to the predictions of the Sharpe-Lintner CAPM, even when the fund managers have no special talent for picking winners.

The CAPM, like Markowitz's (1952, 1959) portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

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[7] The problems are compounded by the large standard errors of estimates of the market premium and of betas for individual stocks, which probably suffice to make CAPM estimates of the cost of equity rather meaningless, even if the CAPM holds (Fama and French, 1997; Pastor and Stambaugh, 1999). For example, using the U.S. Treasury bill rate as the risk-free interest rate and the CRSP value-weight portfolio of publicly traded U.S. common stocks, the average value of the equity premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, with a standard error of 2.4 percent. The two standard error range thus runs from 3.5 percent to 13.1 percent, which is sufficient to make most projects appear either profitable or unprofitable. This problem is, however, hardly special to the CAPM. For example, expected returns in all versions of Merton's (1973) ICAPM include a market beta and the expected market premium. Also, as noted earlier the expected values of the size and book-to-market premiums in the Fama-French three-factor model are also estimated with substantial error.

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BUSINESS CYCLE REFERENCE DATES		DURATION IN MONTHS			
Peak	Trough	Contraction	Expansion	Cycle	
Quarterly dates are in parentheses		*Peak to Trough*	*Previous trough to this peak*	*Trough from Previous Trough*	*Peak from Previous Peak*
	December 1854 (IV)	--	--	--	--
June 1857(II)	December 1858 (IV)	18	30	48	--
October 1860(III)	June 1861 (III)	8	22	30	40
April 1865(I)	December 1867 (I)	32	46	78	54
June 1869(II)	December 1870 (IV)	18	18	36	50
October 1873(III)	March 1879 (I)	65	34	99	52
March 1882(I)	May 1885 (II)	38	36	74	101
March 1887(II)	April 1888 (I)	13	22	35	60
July 1890(III)	May 1891 (II)	10	27	37	40
January 1893(I)	June 1894 (II)	17	20	37	30
December 1895(IV)	June 1897 (II)	18	18	36	35
June 1899(III)	December 1900 (IV)	18	24	42	42
September 1902(IV)	August 1904 (III)	23	21	44	39
May 1907(II)	June 1908 (II)	13	33	46	56
January 1910(I)	January 1912 (IV)	24	19	43	32
January 1913(I)	December 1914 (IV)	23	12	35	36
August 1918(III)	March 1919 (I)	7	44	51	67
January 1920(I)	July 1921 (III)	18	10	28	17
May 1923(II)	July 1924 (III)	14	22	36	40
October 1926(III)	November 1927 (IV)	13	27	40	41
August 1929(III)	March 1933 (I)	43	21	64	34
May 1937(II)	June 1938 (II)	13	50	63	93
February 1945(I)	October 1945 (IV)	8	80	88	93
November 1948(IV)	October 1949 (IV)	11	37	48	45
July 1953(II)	May 1954 (II)	10	45	55	56
August 1957(III)	April 1958 (II)	8	39	47	49
April 1960(II)	February 1961 (I)	10	24	34	32
December 1969(IV)	November 1970 (IV)	11	106	117	116
November 1973(IV)	March 1975 (I)	16	36	52	47
January 1980(I)	July 1980 (III)	6	58	64	74
July 1981(III)	November 1982 (IV)	16	12	28	18
July 1990(III)	March 1991(I)	8	92	100	108
March 2001(I)	November 2001 (IV)	8	120	128	128
December 2007 (IV)	June 2009 (II)	18	73	91	81
Average, all cycles:					
1854-2009 (33 cycles)		17.5	38.7	56.2	56.4*
1854-1919 (16 cycles)		21.6	26.6	48.2	48.9**
1919-1945 (6 cycles)		18.2	35.0	53.2	53.0
1945-2009 (11 cycles)		11.1	58.4	69.5	68.5

* 32 cycles
** 15 cycles

Source: NBER

The determination that the last expansion began in June 2009 is the most recent decision of the Business Cycle Dating Committee of the National Bureau of Economic Research.

Announcement Dates with Links to Announcement Memos

Turning Point Date	Peak or Trough	Announcement Date with Link
June 2009	Trough	September 20, 2010
December 2007	Peak	December 1, 2008
November 2001	Trough	July 17, 2003
March 2001	Peak	November 26, 2001
March 1991	Trough	December 22, 1992
July 1990	Peak	April 25, 1991
November 1982	Trough	July 8, 1983
July 1981	Peak	January 6, 1982
July 1980	Trough	July 8, 1981
January 1980	Peak	June 3, 1980

Other Related Press Releases:

April 12, 2010
January 7, 2008
October 21, 2003
December 21, 1990
December 31, 1979
October 25, 1979
July 27, 1979

Prior to 1979, there were no formal announcements of business cycle turning points.

The NBER does not define a recession in terms of two consecutive quarters of decline in real GDP. Rather, a recession is a significant decline in economic activity spread across the economy, lasting more than a few months, normally visible in real GDP, real income, employment, industrial production, and wholesale-retail sales. For more information, see the latest announcement from the NBER's Business Cycle Dating Committee, dated 9/20/10.

Source:

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An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry

Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan

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This study examines the relationship between interest rates and utility equity risk premiums. We found that an inverse relationship exists, with the equity risk premium changing by 37 basis points for each 100 basis-point change in the 30-year Treasury bond yield. The inverse relationship is stable; however, changes in the relative risk of debt and equity securities produce shifts in the level of risk premiums, regardless of the behavior of Treasury bond yields. We also found that the equity risk premiums were consistently positive over the study period, which conforms to the basic risk/return tenet of finance.

■ Several studies published in recent years support an inverse relationship between utility equity risk premiums and interest rates during the first half of the 1980s. Our study provides a more current examination of this relationship. Our findings support the conclusion that equity risk premiums for utility stocks continue to vary inversely with interest rates. Further, the inverse relationship between interest rates and risk premiums appears stable over the sample period; however, market behavior at certain points in the sample period appears to reflect changes in the market's evaluation of the relative risk of Treasury bonds and utility stocks. For instance, significant differences in the level of the risk premium were observed during certain periods, irrespective of the level of interest rates. Considering the dynamic nature of risk premiums, we discuss how the study may be applicable for estimating the cost of equity for utilities.

Section I provides background information and a literature review. Section II describes the research methodology and the data. Section III provides the empirical results. Section IV furnishes an example to illustrate the model's usefulness. Section V furnishes conclusions.

We would like to thank the Editors and an anonymous referee for their helpful comments. The findings, views, and opinions expressed by the authors do not necessarily represent those of their respective employers.

I. Background and Literature Review

The determination of an appropriate cost of equity is a controversial issue in utility rate proceedings. Bond yields provide a readily observable, definitive measure of the market's required return on that investment; however, such a measure is not readily available for stocks. The indefinite life and uncertainty of a firm's future earnings make it necessary to employ theoretical models to arrive at an estimate of the cost of equity. All theoretical models have strengths and weaknesses, and the focus in utility rate proceedings is often on what is wrong with a particular approach rather than what is right. However, the nebulous nature of the true cost of equity provides no definitive way to assess the superiority of one method's results over another's. Consequently, several cost of equity models are typically used to develop a final estimate.

The risk premium method is an alternative approach to the prevalent discounted cash flow (DCF) model in estimating the cost of equity. A fundamental tenet of financial theory is that riskier investments should command a higher expected return than less risky investments. The risk premium may be defined as the difference, or spread, between expected returns on alternative investments. Financial textbooks usually illustrate risk premiums based on a theoretical risk-free rate and the rate for alternative-risk investments along the security market line.

A widespread application of the risk premium method is based on an average of the realized spreads between total returns on equity and debt investments over some historical period. A refinement of this approach is to calculate the average spread between realized equity total returns and bond yields, in order to obtain a forward-looking measure of the required return on debt. Either type of average risk premium is then added to the current cost of debt to obtain a current cost of equity estimate. The assumption implicit in such approaches is that a constant risk premium is embodied in the current cost of equity. A corollary assumption is that the constant risk premium embodied in expected returns is equal to the average of risk premiums measured from realized returns. In actuality, the time period over which past returns are measured can result in significantly different risk premiums. However, many practitioners of this method argue that if the market risk premium is constant, then it is best approximated by realized returns over very long periods of time. These factors underlie the weaknesses of an ex post risk premium approach. Still, this method has cognitive appeal due to the almost tangible dimension added by the measurement of risk premiums from observed returns. There is also great practical appeal to this approach because it is easy to implement by using readily accessible data from sources like Ibbotson Associates (1993), which provide a regularly updated and consistently available compilation of various risk premiums based on holding periods beginning in 1926.

In recent years, an alternative risk premium model has been proposed. It relies on the expected cost of equity, rather than realized returns, as the appropriate basis for measuring risk premiums. Several studies empirically support the hypothesis that risk premiums, as measured by the expected cost of equity, are not constant but, instead, vary inversely with interest rates (Brigham, Shome, and Vinson, 1985; Harris, 1986; Harris and Marston, 1992; and Shome and Smith, 1988). Generally, studies supporting an ex ante risk premium approach are based on data from as early as the mid-1960s through the mid-1980s. The measurement of the ex ante risk premium holds conceptual appeal because it is consistent with the valuation of equity investments based on *expected* returns. However, a practical concern is the reliability of a risk premium measure that must be based upon an estimate of the cost of equity obtained by some other method, such as a DCF model. If problems exist in the formulation of the model used to estimate the cost of equity, those problems are transferred to the risk premium estimate.

An ex ante risk premium study by Brigham et al. (1985) supported the existence of an inverse relationship between interest rates and utility stock risk premiums from 1980 through the first half of 1984. To determine these risk premiums, they employed a two-stage DCF model to obtain monthly cost of equity estimates for utility stocks. Risk premium measures for each month were then derived by deducting an appropriate Treasury bond yield each month. They found that, prior to 1980, the relationship between equity risk premiums and interest rates had been positive. Shome and Smith (1988) obtained similar results, finding an inverse relationship between interest rates and electric utility risk premiums that continued through 1985. Both studies discussed factors that reduced the impact of regulatory lag on utility stocks from the late 1970s into the early 1980s. Both studies concluded that reduced regulatory lag contributed to shifting the relative risk relationship between debt and utility stocks from positive to negative.

These studies were by and large an outgrowth of the market climate of the early 1980s. During that time, the risk of debt instruments rose in both an absolute sense and compared to stocks. This environment led many to conclude that the risk premium had narrowed and some to even argue it was negative.

Shome and Smith (1988) note that while stocks and bonds are both considered to be hedges against anticipated inflation, common stocks are considered to offer a partial hedge against unanticipated inflation. Therefore, during periods of greater inflation uncertainty, Smith and Shome argue that it would seem reasonable that equity risk premiums would decline as interest rates rise (see Gordon and Halpern, 1976). Stated another way, the risk and required return of the less complete hedge (i.e., debt) would increase at a relatively greater rate than the more complete hedge (i.e., equity), thereby reducing the risk premium during periods of higher uncertainty. However, Carleton, Chambers, and Lakonishok (1983) furnish empirical evidence that risk premiums for utility stocks tend to rise with inflation and interest rates if regulatory lag severely hampers earnings and prevents dividends from keeping pace with inflation.

Harris (1986) also finds an inverse relationship between interest rates and ex ante risk premium measures during the early to mid-1980s, based on utility and broader stock market indices. In a more recent study, Harris and Marston (1992) find an inverse relationship between interest rates and ex ante risk premiums for stocks in the S&P 500, based on data from 1982 to 1991. Blanchard (1993) studied real, rather than nominal, risk premiums between 1926 and 1993. Blanchard hypothesized that the persistence of relatively high risk premiums from the late 1930s through the 1940s could have been due to the market's reaction to the high stock market volatility in the late 1920s and early 1930s. Blanchard also

suggested that changes in inflation had a more temporal impact on the relative risk of debt and equity. He concluded that there was a declining trend in real risk premiums for the broad market since the 1950s, to a current level of about 2% to 3%. He also concluded that inflation contributed to a transitory increase above the trend in the 1970s and to a transitory decrease below the trend in the 1980s. However, Blanchard finds that real risk premiums were negative throughout much of the 1980s, which leads to the question as to whether the method he used to measure risk premiums is consistent with the basic risk/return tenet of financial theory.

II. Risk Premium Method and Data Sources

In our study, risk premiums for the electric utility industry are based on quarterly cost of equity estimates from 1980 through 1993 for a sample group of 30 electric utilities. Companies in the sample group met the following selection criteria over the review period: 1) principally remained an electric utility company, 2) did not file for Chapter 11 protection, and 3) continuously paid dividends.

Cost of equity estimates were obtained using the constant-growth form of the DCF model:

$$k_e = \frac{D_1}{P} + g \quad (1)$$

where

k_e = cost of common equity

D_1 = expected annual dividend per share in the coming year

P = current stock price

g = expected growth rate in dividends per share

Brigham et al. (1985) used a two-stage DCF model to estimate the cost of equity and noted that utility companies "meet the conditions of the constant-growth DCF model rather well." The DCF model is also appropriate for utility stocks, perhaps more than for other stocks, because a significant portion of a utility stock's required return is reflected in the dividend yield component.[1] Constant-growth forms of the DCF model were also used by Harris (1986) and Harris and Marston (1992).

[1]Hansen, Kumar, and Shome (1994) found that traditionally high dividend payout ratios in the electric utility industry provided a cost effective means to monitor and manage agency costs related to stockholder-manager and stockholder-regulator conflict.

Data for the DCF model were obtained from *The Value Line Investment Survey*. Part 1, the Summary and Index section of *Value Line*, contains an estimate of the expected dividend yield (D_1/P) over the next 12 months. The dividend yield for each sample company was based on the *Value Line* yield figure published in the last week of each quarter.

Each company's quarterly growth rate estimate was based on the average of three projected measures: *Value Line*'s projected growth rate in earnings and dividends per share and the projected percentage of common equity retained. The last of the three growth measures is equivalent to the familiar b(r) method of estimating a growth rate. *Value Line*'s growth rates represented a readily available and consistent set of projected growth rates over the study period. Projected growth rates were used in order to be consistent with the ex ante measurement of risk premiums for the study.

The three-month average yield on 30-year Treasury bonds was used as the reference rate. It was subtracted from each company's quarterly cost of equity estimate to derive a risk premium. The risk premiums for each company were then averaged to develop a quarterly risk premium for the electric utility sample.

III. Empirical Results

Figure 1 provides a graph of the observed risk premiums and interest rates. It shows a general inverse trend between the two measures over the period studied. We note that the trend closely resembles the one observed by Brigham et al. (1985). The average interest rate over the study period was 9.77%, and the average risk premium was 3.21%.

To estimate the relationship between electric utility risk premiums and interest rates, we fit a simple linear regression model. Model 1 specifies the regression equation. The risk premium is the dependent variable, and the 30-year Treasury bond yield is the independent variable.

A. Model 1

$$RP_t = \alpha + \beta(TB_t) + \varepsilon \quad (2)$$

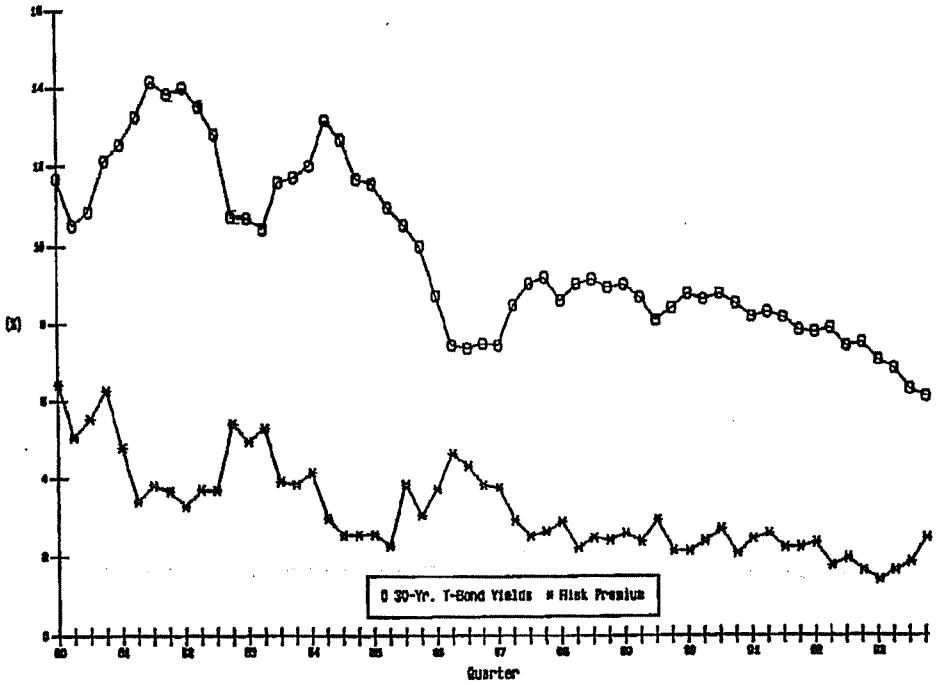
where

RP_t = quarterly average risk premium for all utilities

TB_t = quarterly average 30-year U.S. Treasury bond yield

Initially, we examined our data over the same 1980-1984 time period used by Brigham et al. (1985) and achieved similar results. Expansion of the study period through 1993 produced markedly different results. For example, the adjusted R^2 for Model 1 for the 1980-1993 period was only

Figure 1. Observed Risk Premiums and Treasury Bond Yields Over the Sample Period



0.22, which sharply contrasts with the 0.73 R^2 reported by Brigham et al. (1995) for the 1980-1984 period.

Figure 2 is a graph of all the risk premium data points in the study period for the electric utility industry, with respect to the interest rates at which they were observed. Figure 2 illustrates that there was a divergence in risk premiums that corresponded to interest rates of the same general level during the study period. If a single linear relationship held throughout the observation period, then one would expect very similar risk premium observations at the same general interest rates. This observation led to the hypothesis that perhaps the relative risks of debt and equity were changing over time.

Alternative models were tested to empirically capture the dynamic relationship between risk premiums and interest rates (see Johnston, 1984). We determined that the model specified below was more appropriate than Model 1 for estimating risk premiums over the study period because it would capture this dynamic relationship.

B. Model 2

$$RP_t = \alpha_0 + \alpha_1(D1_t) + \alpha_2(D2_t) + \alpha_3(D3_t) + \alpha_4(D4_t) + \beta(TB_t) + \varepsilon \quad (3)$$

where

RP_t = quarterly average risk premium for all utilities

$D1_t$ = binary variable equal to 1 for Quarter 2-1984 through Quarter 4-1993, and 0 otherwise

$D2_t$ = binary variable equal to 1 for Quarter 1-1987 through Quarter 4-1993, and 0 otherwise

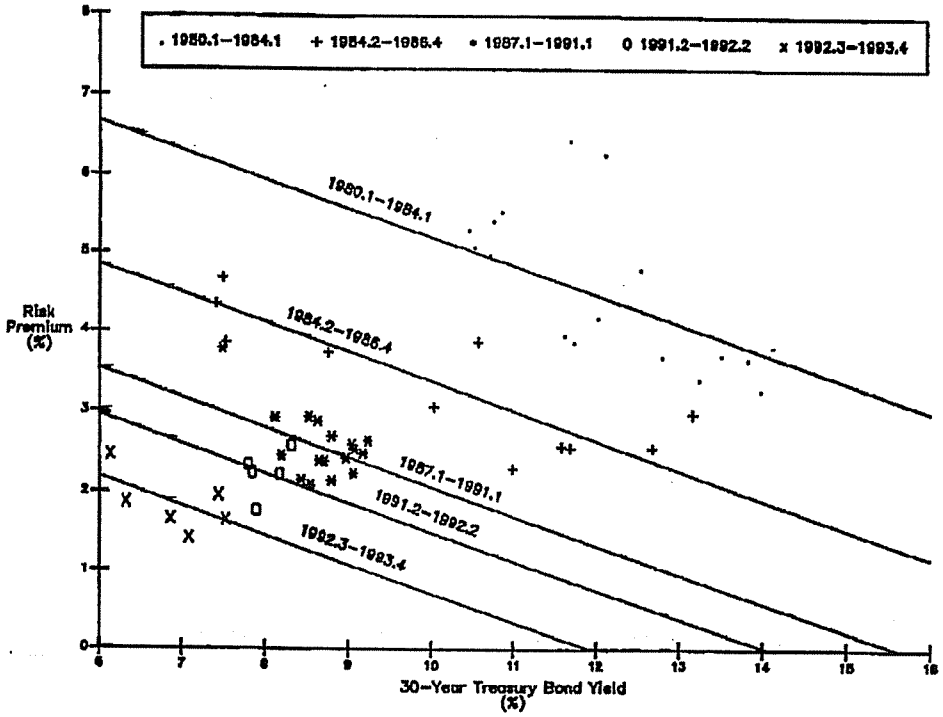
$D3_t$ = binary variable equal to 1 for Quarter 2-1991 through Quarter 4-1993, and 0 otherwise

$D4_t$ = binary variable equal to 1 for Quarter 3-1992 through Quarter 4-1993, and 0 otherwise

TB_t = quarterly average 30-year U.S. Treasury bond yield

The binary variables in Model 2 are included to account for major changes in the relative risks of debt and equity. These changes in relative risk would be reflected as shifts in the level or magnitude of the risk premiums, regardless of the behavior of Treasury bond yields. We did not attempt to determine specific factors that might account for such shifts. Cumulative sum of error tests (see Hall, Johnson, and Lilien, 1990) and break-point Chow tests (see Pindyke and Rubinfeld, 1991) were used to determine the placement

Figure 2. Observed Risk Premiums Plotted Against Treasury Bond Yields



of the binary variables. These tests indicated that significant shifts in the market's evaluation of the relative risk of debt and equity most likely occurred in 1984, 1987, 1991, and 1992.

Table 1 reports the results of fitting Equation (3). These results indicate an inverse relationship between ex ante risk premiums and interest rates over the sample period. A first-order autoregressive correction was made to adjust for the possibility of serial correlation during the sample period (see Johnston, 1984, pp. 321-324). The adjusted R^2 for Model 2 is 0.82. All variables are statistically significantly different from zero at the 0.01 level, except for D3 and D4, which are significant at the 0.05 level. As anticipated, the coefficient estimate of the Treasury bond variable is negative, which indicates the existence of a general inverse relationship between interest rates and risk premiums over the study period.

It is important to note that Model 2 identifies the basic relationship between risk premiums and interest rates, which is defined by the slope coefficient β, as statistically stable over the sample period. Stability of the Treasury bond slope coefficient over the study period was supported by statistical tests that permitted the slope coefficient to change.

C. Interpretation of Empirical Results

The inverse relationship indicated in Table 1 represents approximately 37 basis points for each 100 basis-point change in Treasury bond yields. This result is consistent with the Harris and Marston (1992) study, which found a 36 basis-point inverse relationship between long-term government bond rates and risk premiums for a broader sample of companies for the 1982-1991 period. However, our utility risk premium values are lower than those reported by Harris and Marston for the broader market. One might expect such a difference between the risk premium for utility stocks and the broader market, due to the relatively lower risk of utility stocks.

Harris and Marston found that changes in relative risk, as proxied by a yield spread variable, were important in explaining risk premium changes in subperiods between 1982 and 1991. They also noted, however, that the yield spread variable was more significant in the early 1980s and less significant in the latter 1980s. This phenomenon may be embedded within our intercept dummies, which also exhibited a declining level of magnitude and significance. Interestingly, the break-points for Harris and Marston's

Table 1. Model 2 Regression Results[a]

This table reports the results of fitting Equation (3). The risk premium is the dependent variable.

Variable	Coefficient	Standard Error	t-statistic
Intercept	8.880	0.776	11.444***
TB	-0.368	0.063	-5.878***
D1	-1.828	0.250	-7.318***
D2	-1.309	0.234	-5.598***
D3	-0.569	0.277	-2.051**
D4	-0.773	0.333	-2.320**
Adjusted R^2	0.815	Durbin Waston statistic	1.920

***Significant at the 0.01 level.
**Significant at the 0.05 level.

[a]Regressions were corrected for the possible existence of serial correlation using the Cochran-Orcutt method.

sub-periods closely approximate the break-points indicated by our tests.

Trends in the overall level of risk premiums provide one of the more intriguing comparisons between our results and those of Harris and Marston. Both studies support an inverse relationship throughout similar study periods. However, the late 1980s and early 1990s produced some of the highest risk premiums in Harris and Marston's study, while the same period produced some of the lowest risk premiums observed in our study. These results may be indicative of higher perceived risk for their broader sample relative to our utility stock sample during this period. Electric utility companies generally have significantly lower reported values for beta than would be reported for a broad market sample of companies. While beta is a somewhat controversial measure of risk, Harris and Marston report a significant positive relationship between beta and risk premiums.

Our results indicate that ex ante risk premiums for electric utility stocks remained inversely related to interest rates over the study period when changes regarding the market's evaluation of relative risk are taken into account. We acknowledge the limitation that our regression model is descriptive of the study period only; however, some measure of robustness would appear to be imparted by the fairly wide range of market climates in our study period.

During the study period, any number of events could have had an impact on the relative risks of debt and equity.[2] In all likelihood, this relationship will continue to be affected by innumerable future events. The projected growth rates for utility dividends and earnings during the early 1980s were viewed by some as too high to be sustainable and therefore not reasonable proxies for the long-run growth rate the DCF model requires. Interestingly, the projected dividend and earnings growth rates for the early 1990s have been viewed by some as too low. Therefore, results of a descriptive model developed from ex ante measures over a period of time can help to provide a reasonableness check concerning an estimate at one point in time.

IV. Usefulness of the Model

In developing cost of equity recommendations, the staff of the Virginia State Corporation Commission (VSCC) presently includes ex ante risk premium methods based on the information presented in this study as well as others. For example, the VSCC staff incorporated an earlier version of the model presented in this paper to formulate a cost of equity recommendation for The Potomac Edison Company in a 1993 rate case. At that time, the model included data from 1980 to 1991, which indicated two shifts in the level of risk premiums, one in the second quarter of 1994 and the other in the first quarter of 1987. The estimated slope coefficient at that time was -0.395, or roughly 40 basis points for each 100 basis-point change in interest rates.

Using the 6.3% average yield on 30-year Treasury bonds from July 1993 to September 1993, the model indicated a risk premium of 3.4%. Combined with the 6.3% interest

[2]Over the study period, the relative risks of debt and equity could have been affected by such factors as changing monetary policy, concern over the growing budget deficit, the savings and loan debacle, the Continental Illinois Bank crisis and other bank industry problems resulting from defaulted loans to developing countries, the leveraged buyout binge of the 1980s, and the 1987 stock market crash, to name a few.

rate, this risk premium produced a 9.7% cost of equity estimate. The VSCC staff also adjusted the average risk premium for the study period based on the model's slope coefficient to obtain a cost of equity estimate for the current level of interest rates. Using this approach, the 3.9% difference between the average interest rate over the study period (10.2%) and the recent 3-month average rate (6.3%) was multiplied by the approximate slope coefficient of 0.4%. The resulting 1.6% was then added to the 3.4% average risk premium for the study period to incorporate the inverse relationship between Treasury yields and utility equity risk premiums. This approach indicated a current risk premium of 5.0%, which indicated a current cost of equity of 11.3% when combined with the 6.3% interest rate. A 10 basis-point flotation cost adjustment was added to both estimates, thus providing cost of equity estimates of 9.8% and 11.4% from the risk premium study. The Potomac Edison Company's requested rate increase reflected a 12.50% return on equity (and increased rates had been in effect on an interim basis subject to refund since September 28, 1993). Ultimately, the VSCC authorized a cost of equity range of 10.4% to 11.4% in its Final Order issued on November 18, 1994.

In addition to providing the basis for a supplemental cost of equity estimate, our risk premium study may be applicable in a more relaxed regulatory framework. For example, in its investigation of alternative regulatory methods for local telephone companies, the VSCC established a number of regulatory options for local telephone companies in Case No. PUE930036. The Earnings Incentive Plan option in that case included the provision for an annually authorized return on equity range that would span 300 basis points and be based on a risk premium approach that recognizes an inverse relationship between risk premiums and interest rates. The risk premium for the bottom of the range in each year would be established as 2.0%, plus 0.5 times the difference between 10.0% and the three-month average yield on 30-year Treasury bonds from September through November of the preceding year. The risk premium for the top of the range would be determined in the same manner, except that the calculation would start with a base level of 5.0%. The resulting risk premiums (subject to the constraint that they cannot be less than zero) are added to the same three-month average yield on 30-year Treasury bonds in the risk premium formula to produce the cost of equity range. The average interest rate and risk premium from a study such as ours could easily be incorporated within a plan like the one developed by the VSCC. While the VSCC's plan did not incorporate a provision for the sharing of earnings, one could be included so that returns above the banded range could be shared.

V. Conclusions

This study furnishes evidence that equity risk premiums are not constant. Our results indicate a statistically significant inverse relationship between interest rates and utility equity risk premiums. Yet, considering that our study covers a recent 14-year period, the hypothesis of a constant ex ante risk premium should also be tested over a longer period. It would also be interesting to test whether the long-term average of ex ante risk premiums converges with the long-term average of ex post risk premiums. ■

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Financial Statement Analysis
Theory, Application, and Interpretation

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historical cost. In the discussion of the price-level problem in Chapter 14, it was pointed out that price-level adjustments can validly be made only within the framework of a complete restatement of all elements of the financial statements. Crude "adjustments", such as using the gross asset amount, are apt to be misleading and are generally worse than no adjustments at all.

Long-term liabilities plus equity capital. The use of long-term liabilities plus equity capital as the investment base differs from the "total assets" base only in that current liabilities are excluded as suppliers of funds on which the return is computed. The focus here is on the two major suppliers of longer-term funds, that is, long-term creditors and equity shareholders. In this context, working capital required to support operations is regarded as the excess of current assets over current liabilities.

Shareholders' equity. The computation of return on shareholders' equity measures the return accruing to the owners' capital. As was seen in the discussion of financial leverage in Chapter 18, this return reflects the effect of the employment of debt capital on the owners' return. Since preferred stock, while in the equity category, is usually nevertheless entitled only to a fixed return, it is also omitted from the calculation of the final return on equity computation.

Book versus market values in the investment base

Return on asset calculations are most commonly based on book values appearing in the financial statements rather than on market or fair values that are, in most cases, analytically more significant and relevant. Also, quite often, a return is earned by enterprises on assets that either do not appear in the financial statements or are significantly understated therein. Examples of such assets are intangibles such as patents, trademarks, expensed research and development (R&D) costs, advertising and training costs, and so forth. Other excluded assets may include leaseholds and the value of natural resources discovered.

One avenue to the use of such data is to rely on the valuation that the market places on the equity securities of the enterprise in order to approximate fair values. Thus, we can substitute the market value of equity securities and debt for the book value of total assets in computing a proper investment base.

Difference between investor's cost and enterprise investment base

For purposes of computing the ROI, a distinction must be drawn between the investment base of an enterprise and that of an investor. The investor's investment base is, of course, the price paid for his or her

equity securities. Except for those cases in which he or she acquired such securities at book value, the investment base is going to differ from that of the company in which he or she has invested. In general, the focus in ROI computations is on the return realized by the enterprise rather than the return realized on the investment cost of any one shareholder.

Averaging the investment base

Regardless of the method used in arriving at the investment base, the return achieved over a period of time is always associated with the investment base that was, on average, actually available to the enterprise over that period of time. Thus, unless the investment base did not change significantly during the period, it will be necessary to average it.

The most common method of averaging for the external analyst is that of adding the investment base at the beginning of the year to that at the end of the year and dividing their total by two. Care must, however, be used in employing this method of averaging. Companies in some industries choose a "natural" rather than the calendar business year. Thus, for example, in retailing, the natural business year ends when inventories are at their lowest (e.g., January 31 after the holiday selling season) and when it is easiest to count them. In such case, averaging two year-ends may yield the *lowest* rather than the average amount of assets employed.

In such or similar cases, more accurate methods of averaging, where the data are available, are to average by month-end balances, that is, adding the month-end investment bases and dividing the total by 12, or to average on a quarterly basis.

Relating income to the investment base

In the computation of ROI, the definition of return (income) is dependent on the definition of the investment base.

If the investment base is defined as comprising total assets, then income *before* interest expense is used.[4] The exclusion of interest from income deductions is due to its being regarded as a payment for the use of money to the suppliers of debt capital in the same way that dividends are regarded as a reward to suppliers of equity capital. Before deductions for interest or dividends, income is used when it is related to total assets or to long-term debt plus equity capital (assuming most of the interest expense is on long-term obligations).

The income of a consolidated entity that includes a subsidiary that is partially owned by a minority interest usually reflects a deduction for the

[4] Interest expense means interest incurred less interest capitalized. In theory, the amount of previously capitalized interest currently amortized and included in expenses should also be added back to income.

minority's share in that income. The consolidated balance sheet, however, includes all the assets of such a subsidiary, i.e., those belonging to the parent as well as those belonging to the minority (see also Chapter 9). Because the investment in the denominator includes all the assets of the consolidated entity, the income (in the numerator) should include all the income (or loss), not just the parent's share. For this reason, the minority's share of earnings (or loss) must be added back to income in computing return on total assets. When the denominator is the equity capital only, the minority share in income (or loss) need not be added back if equity capital excludes minority interest.

When the return on the equity capital is computed, net income *after* deductions for interest and preferred dividends is used. If the preferred dividends are cumulative, they are deducted in arriving at the balance of earnings accruing to the common stock, whether these dividends were declared or not.

The final ROI must always reflect all applicable costs and expenses and that includes income taxes. Some computations of ROI nevertheless omit deductions of income taxes. One reason for this practice is the desire to isolate the effects of tax management from those of operating performance. Another reason is that changes in tax rates affect comparability over the years. Moreover, companies that have tax loss carry-forwards find that the deduction of taxes from income adds confusion and complications to the ROI computations.

It must, however, be borne in mind that income taxes reduce the final return and that they must be taken into consideration particularly when the return on shareholders' equity is computed.

ADJUSTING THE COMPONENTS OF THE ROI FORMULA

In computing any measure or ratio, the analyst uses the amounts in the financial statements only as starting points. As was seen in the discussion in Chapter 18 on the adjustment of the debt-to-equity ratios, some amounts need analytical adjustment and some amounts not found in the financial statements need to be included in the adjusted computation. Reference to the discussion in Chapter 18 will reveal that some of the items discussed therein, such as adjustment of inventory amounts, may affect the ROI computation while others, such as reclassification of deferred taxes, may not. Moreover, some adjustments, such as those relating to inventory amounts, affect both the numerator and the denominator of the formula, thus moderating the net effect on the ratio.

The computation of ROI under the various concepts of "investment base" discussed above will now be illustrated by means of the data contained in Exhibits 19–1 and 19–2. The computations are for the year 19x9 and based on figures rounded to the nearest million dollars.

169 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and Bernard L. McNamee.

Association of Businesses Advocating Tariff Equity
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

Docket No. EL14-12-003

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation
Mississippi Delta Energy Agency
Clarksdale Public Utilities Commission
Public Service Commission of Yazoo City
Hoosier Energy Rural Electric Cooperative, Inc.

Docket No. EL15-45-000

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

OPINION NO. 569

ORDER ON BRIEFS, REHEARING, AND INITIAL DECISION

(Issued November 21, 2019)

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1. On November 15, 2018, the Commission issued an Order Directing Briefs in the above-captioned proceedings.[1] The Briefing Order directed the participants in the above-captioned proceedings to submit briefs regarding: (1) a proposed framework for determining whether an existing base return on equity (ROE) is unjust and unreasonable under the first prong of Federal Power Act (FPA) section 206;[2] and (2) a revised methodology for determining just and reasonable base ROEs under the second prong of FPA section 206.[3] As discussed below, we will adopt the proposal in the Briefing Order, with certain revisions. Principally, we will not adopt the use of the expected earnings (Expected Earnings) and risk premium (Risk Premium) models in our ROE analyses under the first and second prongs of section 206, and instead will use only the discounted cash flow (DCF) model and capital-asset pricing model (CAPM) in our ROE analyses under both prongs of section 206.

I. Background

A. Opinion No. 531 *et seq.*

2. In Opinion No. 531, the Commission adopted certain changes to its use of the DCF methodology for evaluating and setting the Commission-allowed ROE for the New England transmission owners (New England TOs). In particular, the Commission elected to replace the "one-step" DCF model, which considers only short-term growth projections for a public utility, with a "two-step" model that considers both short- and long-term growth projections.[4] The Commission also departed from its typical practice of setting the just and reasonable ROE of a group of utilities at the midpoint of the zone of reasonableness. The Commission explained that evidence of "anomalous" capital market conditions, including "bond yields [that were] at historic lows," made the Commission "less confiden[t] that the midpoint of the zone of reasonableness . . . accurately reflects the [ROE] necessary to meet the *Hope* and *Bluefield* capital attraction

[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (Briefing Order).

[2] 16 U.S.C. § 824e (2018).

[3] Briefing Order, 165 FERC ¶ 61,118 at PP 13-14.

[4] *See generally*, *Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co*., Opinion No. 531, 147 FERC ¶ 61,234, at PP 8, 32-41, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *rev'd, Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*).

standards."[5] The Commission therefore looked to four alternative benchmark models: three financial models—the Risk Premium model, CAPM, and Expected Earnings model[6]—as well as a comparison with the ROEs approved by state public utility commissions.[7] In considering those models, the Commission emphasized that it was not departing from its long-standing reliance on the DCF model, but rather relying on those models only to "inform the just and reasonable placement of the ROE within the zone of reasonableness established . . . by the DCF methodology."[8] Based on these alternative models, the Commission determined that an ROE of 10.57 percent, the midpoint of the upper half of the zone of reasonableness produced by the two-step DCF model, would be just and reasonable. Because that figure differed from the New England TOs' existing 11.14 percent ROE, the Commission concluded that the existing base ROE had become unjust and unreasonable and it therefore set New England TOs' base ROE at 10.57 percent, pending a paper hearing concerning the long-term growth projection to use in the DCF analysis. Following that hearing, in Opinion No. 531-A the Commission reaffirmed its conclusion that 10.57 percent was the just and reasonable ROE and that New England TOs' existing ROE was unjust and unreasonable. The Commission required New England TOs to submit a compliance filing to implement their new ROEs effective October 16, 2014—the date of Opinion No. 531-A.

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[5] Opinion No. 531, 147 FERC ¶ 61,234 at PP 144-145 & n.285. "*Hope*" and "*Bluefield*" refer to a pair of U.S. Supreme Court cases that require the Commission "to set a rate of return commensurate with other enterprises of comparable risk and sufficient to assure that enough capital is attracted to the utility to enable it to meet the public's needs." *Boroughs of Ellwood City, Grove City, New Wilmington, Wampum, & Zelienople, Pa. v. FERC*, 731 F.2d 959, 967 (D.C. Cir. 1984) (citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*) and *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of W.V.*, 262 U.S. 679 (1923) (*Bluefield*)).

[6] As discussed further below, the Risk Premium model and CAPM estimate cost of equity using the premium that investors expect to earn on a stock investment over and above the return that they expect to earn on a bond investment, and the Expected Earnings model is a method of calculating the earnings that an investor expects to receive on the book value of a particular stock.

[7] Opinion No. 531, 147 FERC ¶ 61,234 at PP 147-149.

[8] *Id.* P 146.

B. Opinion No. 551 *et seq.*

3. On November 12, 2013, multiple complainants[9] filed a complaint (First Complaint) in Docket No. EL14-12-000 pursuant to FPA section 206, alleging, among other things, that the Midcontinent Independent System Operator, Inc.'s (MISO) transmission-owning members' (MISO TOs) base ROE reflected in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) was unjust and unreasonable.[10] At the time of the First Complaint, MISO TOs had a base ROE of 12.38 percent (except for the ATCLLC zone which had a 12.20 percent ROE),[11] and their total ROE—i.e., the base ROE plus any ROE adders approved by the Commission—was not permitted to exceed 15.96 percent. The Commission established the MISO TOs'

[9] The complainants consist of a group of large industrial customers: Association of Businesses Advocating Tariff Equity (ABATE); Coalition of MISO Transmission Customers (Coalition of MISO Customers); Illinois Industrial Energy Consumers (IIEC); Indiana Industrial Energy Consumers, Inc. (INDIEC); Minnesota Large Industrial Group (MLIG); and Wisconsin Industrial Energy Group.

[10] The following MISO transmission owners were named in the First Complaint: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC (ATC); Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; METC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company; and Wolverine Power Supply Cooperative, Inc. Intervenor Xcel Energy Services Inc. did not join certain of the MISO Transmission Owners' pleadings in this proceeding, but generally supports this brief on behalf of respondents Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation.

[11] For the sake of clarity, we refer to this ROE of the MISO TOs as 12.38 percent in this order, without separately identifying that the ATCLLC zone had a 12.20 percent ROE. Our discussion and decisions with respect to the MISO TOs' 12.38 percent ROE also apply to the 12.20 percent ATCLLC ROE.

preexisting 12.38 percent ROE in a 2002 decision.[12] That ROE was based on a DCF analysis using financial data for the six-month period ending February 2002.[13] On October 16, 2014, the same date that the Commission issued Opinion No. 531-A, it set the First Complaint for hearing before an Administrative Law Judge and established a refund effective date of November 12, 2013.[14]

4. Following the hearing, the Presiding Judge issued an Initial Decision,[15] and the Commission subsequently issued Opinion No. 551.[16] In Opinion No. 551, the Commission calculated the just and reasonable ROE using the two-step DCF methodology from Opinion No. 531 and financial data for the period January 1 through June 30, 2015. The Commission affirmed the conclusions of Initial Decision (I), finding that the Presiding Judge correctly applied the two-step DCF analysis required by Opinion No. 531.[17] The Commission also affirmed the Presiding Judge's determination that, as in Opinion No. 531, there were anomalous capital market conditions such that the Commission had less confidence that the midpoint of the zone of reasonableness produced by a mechanical application of the DCF methodology satisfied the capital

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[12] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, *initial decision affirmed as to base ROE*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC ¶ 61,143 (2003), *order on remand*, 106 FERC ¶ 61,302 (2004). The ATCLLC zone base ROE of 12.20 percent was established as part of a settlement agreement that was filed with the Commission on March 26, 2004. In Docket No. ER04-108-000, the Commission approved the uncontested settlement. *Am. Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

[13] *Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, App. A.

[14] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014) (MISO I Hearing Order), *order on reh'g*, 156 FERC ¶ 61,060 (2016) (MISO I Rehearing Order). In the MISO I Rehearing Order, the Commission denied requests for rehearing and clarification of the MISO I Hearing Order and clarified that non-public utility transmission owners are subject to the outcome of that proceeding. MISO I Rehearing Order, 156 FERC ¶ 61,060 at PP 47-48.

[15] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015) (Initial Decision (I)).

[16] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016) (affirming Initial Decision (I), 153 FERC ¶ 63,027).

[17] *See generally* Opinion No. 551, 156 FERC ¶ 61,234 at P 9.

attraction standards of *Hope* and *Bluefield*.[18] The Commission found that the Presiding Judge reasonably considered evidence of alternative methodologies for determining the ROE and the ROEs approved by state regulatory commissions, for purposes of deciding to set the ROE at the central tendency of the upper half of the zone of reasonableness, setting the base ROE for MISO TOs at 10.32 percent.[19] The Commission required MISO TOs to submit a compliance filing to implement their new ROEs effective September 28, 2016, the date of Opinion No. 551, and to provide refunds for the November 12, 2013-February 11, 2015 refund period. Following the issuance of Opinion No. 551, numerous parties submitted requests for rehearing.

C. Second Complaint Against MISO TOs' ROE

5. On February 12, 2015, a new set of complainants[20] filed a complaint (Second Complaint) also alleging that the MISO TOs' base ROE of 12.38 percent was unjust and unreasonable.[21] Relying on an updated two-step DCF analysis, the Second Complaint

[18] *Id.*

[19] *Id.*

[20] Complainants for the Second Complaint consist of: Arkansas Electric Cooperative Corporation (Arkansas Electric Cooperative); Mississippi Delta Energy Agency and its two members, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and Public Service Commission of Yazoo City of the City of Yazoo City, Mississippi; and Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier Cooperative).

[21] The following MISO transmission owners were named in the Second Complaint: ALLETE, Inc. (for its operating division Minnesota Power, Inc. and its wholly-owned subsidiary Superior Water Light, & Power Company; Ameren Illinois Company; Union Electric Company (identified as Ameren Missouri); Ameren Transmission Company of Illinois; ATC; Cleco Power LLC; Duke Energy Business Services, LLC; Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company, ITC Midwest LLC, and Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Montana-Dakota Utilities Co., Northern Indiana Public Service Company; Northern States Power Company-Minnesota; Northern States Power Company-Wisconsin; Otter Tail Power Company; and Southern Indiana Gas & Electric Company.

complainants argued that the base ROE should be no higher than 8.67 percent.[22] On June 18, 2015, the Commission established hearing procedures and set a refund effective date of February 12, 2015.[23]

6. Parties filed requests for rehearing of the MISO II Hearing Order, and on July 21, 2016, the Commission generally denied these rehearing requests.[24] Following the MISO II Hearing Order, the Presiding Judge issued the Initial Decision on June 30, 2016.[25] The Presiding Judge adopted a zone of reasonableness of 6.75 percent to 10.68 percent based on financial data for the period July 1, 2015 through December 31, 2015. The Presiding Judge also determined that the anomalous market conditions identified in Opinion No. 531 persisted and, after considering the alternative benchmark methodologies, that the just and reasonable ROE was 9.70 percent—halfway between the midpoint and the upper bound of the zone of reasonableness. The participants filed briefs on and opposing exception, which are currently pending before the Commission.

D. ***Emera Maine***

7. On April 14, 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its *Emera Maine* decision, vacating and remanding Opinion No. 531 *et seq*. As an initial matter, the D.C. Circuit was not persuaded by New England TOs' argument that an ROE within the DCF-produced zone of reasonableness could not be deemed unjust and unreasonable. The D.C. Circuit explained that the zone of reasonableness established by the DCF is not "coextensive" with the "statutory" zone of reasonableness envisioned by the FPA.[26] Accordingly, the D.C. Circuit concluded that the fact that New England TOs' existing ROE fell within the zone of reasonableness

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[22] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015) (MISO II Hearing Order), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (MISO II Rehearing Order).

[23] MISO II Hearing Order, 151 FERC ¶ 61,219 at P 1.

[24] *See* MISO II Rehearing Order, 156 FERC ¶ 61,061.

[25] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016) (Initial Decision (II)).

[26] *Emera Maine*, 854 F.3d at 22-23.

produced by the DCF did not necessarily indicate that it was just and reasonable for the purposes of the FPA.[27]

8. Nevertheless, the D.C. Circuit found that the Commission had not adequately shown that the New England TOs' existing ROE was unjust and unreasonable. The D.C. Circuit explained that the FPA's statutory "zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE" and that whether a particular ROE is unjust and unreasonable depends on the "particular circumstances of the case."[28] Thus, the fact that New England TOs' existing ROE did not equal the just and reasonable ROE that the Commission would have set using the current DCF inputs did not necessarily indicate that New England TOs' existing ROE fell outside the statutory zone of reasonableness.[29] As such, the D.C. Circuit concluded that Opinion No. 531 "failed to include an actual finding as to the lawfulness of [New England TOs'] existing base ROE" and that its conclusion that their existing ROE was unjust and unreasonable was itself arbitrary and capricious.[30]

9. The D.C. Circuit also found that the Commission had not adequately shown that the 10.57 percent ROE that it set was just and reasonable. Although recognizing that the Commission has the authority "to make 'pragmatic adjustments' to a utility's ROE based on the 'particular circumstances' of a case," the D.C. Circuit nevertheless concluded that the Commission had not explained why setting the ROE at the upper midpoint was just and reasonable.[31] The D.C. Circuit noted, in particular, that the Commission relied on the alternative models and state-regulated ROEs to support a base ROE *above* the midpoint, but that it did not rely on that evidence to support an ROE *at* the upper midpoint.[32]

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[27] *Id.* at 23.

[28] *Id.* at 23, 26.

[29] *Id.* at 27 ("To satisfy its dual burden under section 206, FERC was required to do more than show that its single ROE analysis generated a new just and reasonable ROE and conclusively declare that, consequently, the existing ROE was per se unjust and unreasonable.").

[30] *Id.*

[31] *Id.* (quoting *FPC v. Nat. Gas Pipeline Co. of America*, 315 U.S. 575, 586 (1942)).

[32] *Id.* at 29 ("FERC's reasoning is unclear. On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but

Similarly, the D.C. Circuit noted that the Commission had concluded that a base ROE of 9.39 percent—the midpoint of the zone of reasonableness—might not be sufficient to satisfy *Hope* and *Bluefield* or to allow the utility to attract capital, but that the Commission had not similarly explained how a 10.57 percent base ROE was sufficient to meet either of those conditions. Because the D.C. Circuit found that the Commission had not pointed to record evidence supporting the specific point at which it set New England TOs' ROE, the D.C. Circuit held that the Commission had not articulated the "rational connection" between the evidence and the rate that the FPA demands.[33]

10. Based on the D.C. Circuit's conclusion that the Commission had not met its burden either under the first or the second prong of FPA section 206, it vacated and remanded Opinion No. 531 *et seq.*[34] Thus, the current state of affairs concerning the MISO TOs' ROE is this: There are two currently pending complaints against their ROE, both of which have been fully litigated before a Presiding Judge. The D.C. Circuit vacated the Commission's determinations in Opinion No. 531, upon which the Commission relied extensively in its order on the First Complaint (i.e., Opinion No. 551), meaning that Opinion No. 531 is no longer precedential,[35] even though the Commission remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.[36] In the meantime, MISO TOs are continuing to collect their 10.32 percent ROE, although the Commission has broad remedial authority to correct its legal error in order to make whatever ROE it sets on rehearing effective as of the date of Opinion No. 551.[37]

E. Briefing Orders

11. On October 16, 2018, the Commission issued an order proposing a methodology for addressing the issues that were remanded to the Commission in *Emera Maine* and

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on the other hand, it stressed that none of these analyses were used to select the 10.57 percent base ROE.").

[33] *Id.* at 28-30.

[34] *Id.* at 30.

[35] *ISO New England Inc. v. Bangor Hydro-Electric Co.*, 161 FERC ¶ 61,031, at P 28 (2017).

[36] *Emera Maine*, 854 F.3d at 30.

[37] *See ISO New England Inc. v. Bangor Hydro-Electric Co.*, 161 FERC ¶ 61,031 at PP 24, 34.

establishing a paper hearing on whether and how this methodology should apply to the four complaint proceedings concerning the New England TOs' ROE.[38] In the *Coakley* Briefing Order, the Commission proposed to change its approach to determining base ROE by giving equal weight to four financial models, instead of primarily relying on the DCF methodology. The Commission stated that evidence indicates that investors do not rely on any one model to the exclusion of others. Therefore, relying on multiple financial models makes it more likely that our ROE determination will accurately reflect how investors make their investment decisions.

12. Specifically, the Commission proposed to rely on three financial models that produce zones of reasonableness—the DCF model, CAPM, and Expected Earnings model—to establish a composite zone of reasonableness. The zone of reasonableness produced by each model would be given equal weight and averaged to determine the composite zone of reasonableness.[39]

13. The Commission also proposed a framework for using the composite zone of reasonableness in evaluating whether an existing base ROE remains just and reasonable. The Commission proposed that, in order to find a utility's existing ROE unjust and unreasonable under the first prong of FPA section 206, its ROE must be outside a range of presumptively just and reasonable ROEs for a utility of its risk profile, absent additional evidence to the contrary. In other words, the Commission would dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile unless that presumption is sufficiently rebutted. The Commission explained that, by the same token, a finding that the existing ROE of a utility falls outside that range would support a holding that the ROE has become unjust and unreasonable, absent additional evidence to the contrary.[40]

14. The Commission explained that it is appropriate to calculate the applicable ranges of presumptively just and reasonable ROEs based on a utility's risk profile because a utility's risk profile remains the "particular circumstance[]" most relevant to determining whether a point within a zone of reasonableness is a just and reasonable ROE for that utility.[41] The Commission further concluded that the "principal consideration for

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[38] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order).

[39] *See id.* PP 16, 30.

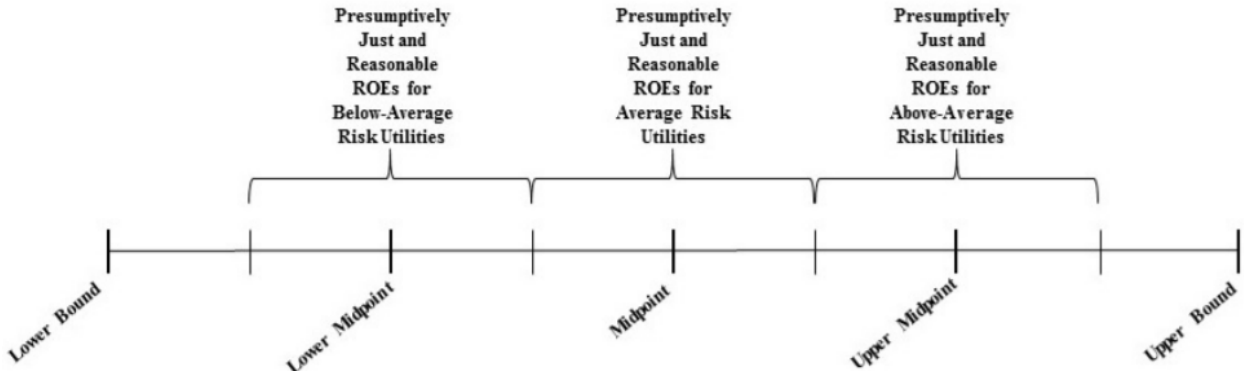
[40] *See id.* PP 16, 28.

[41] *Id.* P 24 (quoting *Emera Maine*, 854 F.3d at 23).

determining whether an existing ROE within the overall zone of reasonableness has become unjust and unreasonable is the risk profile of the utility or utilities for which the Commission is setting the ROE."[42]

15. The Commission proposed that the applicable range of presumptively just and reasonable ROEs for a utility should correspond to those points that are closer to the ROE that the Commission should set for that utility than to the ROE for a utility of a different risk profile.[43] For example, the Commission explained that it typically would be unjust and unreasonable for an average risk utility to receive an ROE that is closer to the ROE that would be just and reasonable for a utility of above- or below-average risk.[44] In particular, for average risk utilities, the Commission proposed that the presumptively just and reasonable range would be the quartile of the zone of reasonableness centered on the central tendency of the composite zone of reasonableness. For below average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of reasonableness. For above average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness.[45] The Commission illustrated how these presumptively just and reasonable quartile ranges would be divided as follows:

Figure 1: Zone of Reasonableness Quartiles



16. For purposes of establishing a new just and reasonable base ROE when the existing base ROE has been shown to be unjust and unreasonable, the Commission proposed using the above three models, plus the Risk Premium model. The Risk

[42] *Id.* P 28.

[43] *Id.* P 27.

[44] *Id.* P 26.

[45] *Id.*

Premium model produces a single numerical point rather than a range; therefore the Commission did not propose to use it to establish a composite zone of reasonableness. The Commission proposed to determine a new just and reasonable ROE for average risk utilities by determining the midpoint/medians of each zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models and averaging those ROEs with the Risk Premium ROE, giving equal weight to each of the four figures. The Commission proposed to use the midpoint/medians of the lower and upper halves of the zones of reasonableness to determine ROEs for below average and above average risk utilities, respectively, and average those ROEs with the Risk Premium ROE.[46]

17. On November 15, 2018, the Commission issued the Briefing Order in these proceedings. In that order, the Commission similarly established a paper hearing on whether and how the methodology proposed in the *Coakley* Briefing Order should apply to the two proceedings pending before the Commission involving MISO TOs' ROE.[47]

II. Overview

18. As discussed below, we adopt the revised base ROE methodology proposed in the Briefing Order, with certain revisions. The Commission will use this methodology to determine whether an existing base ROE is unjust and unreasonable under the first prong of section 206, and for determining a new just and reasonable replacement base ROE under the second prong of section 206 when an existing ROE has been shown to be unjust and unreasonable. However, we will not use the Expected Earnings model or Risk Premium model in our revised base ROE methodology, for the reasons we discuss below. As a result, we will use the DCF model and CAPM in our determinations under the first and second prongs of section 206, as we discuss further below. These models are the two methods most commonly used by investors for estimating the cost of equity.[48] We will also use the ranges of presumptively just and reasonable ROEs in our analysis under the first prong of section 206, as the Commission proposed in the Briefing Order.

19. In this order, we also make other, more specific findings regarding the implementation of these models in our revised base ROE methodology. In particular, in the DCF model, we will use a two-step DCF analysis that incorporates a long-term growth rate, use the short-term growth rate to calculate the (1+.5g) adjustment to dividend yield, and use only the Institutional Brokers' Estimate System (IBES) as the source of short-term earnings growth estimates. In the CAPM, we will: (1) estimate the

[46] *Id.* P 17.

[47] *See* Briefing Order, 165 FERC ¶ 61,118 at P 1.

[48] Trial Staff Initial Br. (I) at 8 (citing *In re Connect Am. Fund*, 28 FCC Rcd. 7123, 7148 (2013)); Trial Staff Initial Br. (II) at 7 (citing same).

CAPM expected market return using a forward-looking approach; (2) use a one-step DCF model without any long-term growth projection for the DCF analysis within the CAPM; (3) use only IBES as the source of short-term earnings growth estimates in the DCF analysis within the CAPM; (4) screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20 percent; and (5) include a size premium adjustment. In addition, we also adopt a revised low-end outlier test that eliminates DCF and CAPM proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20 percent of the CAPM risk premium.

20. Applying this revised base ROE methodology to the facts of the First Complaint, we review the MISO TOs' 12.38 percent ROE that was the existing ROE reviewed in Opinion No. 551, which is pending on rehearing before us here. Under the revised base ROE methodology, the composite zone of reasonableness in the First Complaint proceeding is from 7.52 percent to 12.24 percent.[49] As discussed below, we find that MISO TOs are of average risk, therefore the applicable quartile range of presumptively just and reasonable ROEs for MISO TOs in the First Complaint proceeding is from 9.29 percent to 10.47 percent.[50] Accordingly, MISO TOs' 12.38 percent ROE is not treated as presumptively just and reasonable and in fact, is higher than the 12.24 percent top of the overall zone of reasonableness. As discussed below, in light of this and the other circumstances of the case, we find that MISO TOs' 12.38 percent is unjust and unreasonable. Having found that MISO TOs' existing 12.38 percent ROE is unjust and unreasonable, we then find that the just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 9.88 percent because MISO TOs are of average risk and the midpoint of the composite zone of reasonableness is 9.88 percent.[51] Accordingly, we grant rehearing of Opinion No. 551 in part to require the MISO TOs to adopt a 9.88 percent ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32 percent ROE, and provide refunds, with interest for the applicable refund period, as discussed below.

21. As discussed further below, in the Second Complaint proceeding, the ROE to be reviewed is the 9.88 percent ROE established in the First Complaint proceeding that is effective prospectively from September 28, 2016. Under the revised base ROE methodology, the composite zone of reasonableness in the Second Complaint proceeding is from 7.78 percent to 11.66 percent.[52] As discussed below, we continue to find that

[49] *See* Appendix C.

[50] *See id.*

[51] *See id.*

[52] *See id.*

MISO TOs are of average risk in the Second Complaint proceeding; therefore the applicable quartile range of presumptively just and reasonable ROEs for MISO TOs in that proceeding is from 9.23 percent to 10.20 percent.[53] The 9.88 percent ROE that the Commission is reviewing for purposes of the Second Complaint proceeding falls within that range; therefore, the Commission presumes it to be just and reasonable. As discussed below, we find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. Accordingly, we affirm in part and reverse in part the Initial Decision (II) in the Second Complaint proceeding, dismiss the Second Complaint, and find that no refunds should be issued as a result of the resolution of that complaint.

III. Use of Multiple Models Generally

A. Background

22. As noted above, in the Briefing Order, the Commission proposed to change its methodology for analyzing base ROEs under section 206 to rely on multiple financial models instead of primarily relying on only the DCF model. Specifically, the Commission proposed to rely on the three financial models that produce zones of reasonableness—the DCF, CAPM, and Expected Earnings models—in its ROE analysis under the first prong of section 206, and to rely on four financial models—the Risk Premium model, in addition to those used in the first prong analysis—in its ROE analysis under the second prong of section 206.[54]

23. The Commission explained that changing its base ROE methodology to rely on these multiple financial models is appropriate because investors do not rely on any single financial model to make their investment decisions, but instead rely on these models and other methods to varying degrees. The Commission reasoned that, therefore, a more accurate estimate of what ROE is needed to induce investors to invest in a utility—i.e., what ROE a utility must offer in order to attract capital—would be provided by relying on multiple financial models because that is what investors do when making investment decisions.[55] The Commission further explained that relying on multiple financial models is appropriate because any one model has the potential for errors or inaccuracies and

[53] *See id.*

[54] *See* Briefing Order, 165 FERC ¶ 61,118 at PP 17-18.

[55] *See id.* PP 37-49.

relying on multiple models together reduces the risks that errors or inaccuracies in any one model will produce an inaccurate cost of equity estimate.[56]

B. CAPs

24. Complaint-Aligned Parties (CAP)[57] argue that the Commission should continue to rely on the DCF as the primary, if not exclusive, model in its ROE analyses. CAPs assert that the DCF method still remains the most robust and instructive market-based method to use in the determination of just and reasonable ROEs.[58] CAPs contend that the Commission's concerns about continuing to rely on only the DCF model are misplaced.[59]

25. CAPs argue that, to the extent the Commission adopts an ROE methodology that relies upon the CAPM model, it must be implemented properly and that CAPs' witness

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[56] *See id.* PP 38-40.

[57] For purposes of the CAPs briefs in the First Complaint proceeding, CAPs include the following entities: American Municipal Power, Inc. (AMP); ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and Wisconsin Industrial Group (WIEC) (collectively, Joint Complainants); Joint Consumer Advocates, including Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Customers, including Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; Organization of MISO States, Inc. (OMS); Mississippi Public Service Commission (MS PSC), Missouri Public Service Commission (MO PSC) and Missouri Joint Municipal Electric Utility Commission (MJMEUC) (collectively, Missouri-Mississippi Parties or MOMs); and Southwest Electric Cooperative, Inc. (SWEC). For purposes of the CAPs briefs in the Second Complaint proceeding, CAPs include Industrial Consumer Groups (ICG), comprising ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and WIEC; Joint Consumer Advocates, comprising Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Complainants and Intervenor (JCI), comprising Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; OMS; Missouri-Mississippi Parties; and SWEC.

[58] CAPs Initial Br (I) at 12-14; CAPs Initial Br. (II) at 11-14; CAPs Reply Br. (I) at 6-9; CAPs Reply Br. (II) at 21-24.

[59] CAPs Initial Br. (I) at 14-22; CAPs Initial Br. (II) at 14-22.

Mr. Gorman provides a CAPM analysis that "produces reliable results."[60] CAPs similarly assert that, if the Commission uses the Risk Premium model in its ROE methodology, it should be revised in the manner recommended by CAPs and "Mr. Gorman addresses the correct approach for conducting a Risk Premium study that produces a reliable cost-of-equity estimate."[61] CAPs oppose the use of the Expected Earnings model in the Commission's ROE methodology, arguing that it should receive no weight.[62] CAPs contend that, at the most, the Expected Earnings model should be given significantly less weight than market-based models.[63]

C. MISO TOs

26. MISO TOs support the Commission's proposal to use multiple financial models in its ROE methodology, asserting that the multiple model approach is a significant improvement over the approach of relying on only the DCF model.[64] MISO TOs assert that the additional three models which the Commission proposes to use are widely relied upon by investors and present transparent cost-of-capital estimates.[65] MISO TOs propose certain modifications to the DCF, CAPM, and Expected Earnings models and urge the Commission to apply the Risk Premium model in the same manner in this proceeding as the Commission proposed in the New England TOs' ROE complaint proceedings.[66]

D. Trial Staff

27. Trial Staff proposes various adjustments to the DCF, CAPM and Risk Premium models, but does not oppose the Commission using them in its ROE methodology in general.[67] Trial Staff argues that the Expected Earnings model should not be included in

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[60] CAPs Initial Br. (I) at 27-28; CAPs Initial Br. (II) at 27.

[61] CAPs Initial Br. (I) at 34-35; CAPs Initial Br. (II) at 34-35.

[62] CAPs Initial Br. (I) at 14; CAPs Initial Br. (II) at 14.

[63] CAPs Initial Br. (I) at 46; CAPs Initial Br. (II) at 46.

[64] MISO TOs Initial Br. (I) at 1-2; MISO TOs Initial Br. (II) at 5; MISO TOs Reply Br. (I) at 5-19; MISO TOs Reply Br. (II) at 5-19.

[65] MISO TOs Initial Br. (I) at 4; MISO TOs Initial Br. (II) at 6.

[66] MISO TOs Initial Br. (I) at 6-7; MISO TOs Initial Br. (II) at 24.

[67] *See* Trial Staff Initial Br. (I) at 2; Trial Staff Initial Br. (II) at 2; Trial Staff Reply Br. (I) at 8-19; Trial Staff Reply Br. (II) at 8-19.

the Commission's ROE methodology. Trial Staff asserts that the Commission has used market-based models for over 30 years to determine the cost of equity, but the Expected Earnings model is not a market-based method for estimating the cost of equity. Trial Staff also asserts that there is little evidence that the Expected Earnings approach is widely used by investors.[68]

E. LPSC

28. The Louisiana Public Service Commission (LPSC) contends that the Commission should require certain changes to the Risk Premium model and CAPM if those models are used in the Commission's ROE methodology, but does not oppose the use of those models in general.[69] LPSC argues that the Expected Earnings model should not be used in the Commission's ROE methodology, arguing, among other things, that the model has no legitimate relationship to investors' required return on equity.[70] LPSC argues that, if the Commission decides to use the Expected Earnings model, then it should adjust the analysis for market-to-book ratios.[71]

F. RPGI

29. Resale Power Group of Iowa (RPGI) argues that the Commission should "reaffirm the primacy of the DCF model" and continue to use a DCF-based approach for setting ROEs.[72] RPGI contends that, if the Commission uses multiple financial models in its ROE methodology, then the Commission should make changes to the CAPM and Risk Premium models, but it does not oppose the use of these two financial models in general.[73] RPGI endorses Trial Staff's proposal to exclude the Expected Earnings model from the Commission's ROE methodology.[74]

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[68] Trial Staff Initial Br. (I) at 2-3; Trial Staff Initial Br. (II) at 2-3.

[69] LPSC Initial Br. at 5-9, 29-42.

[70] *Id.* at 1-5, 13-29.

[71] *Id.* at 29.

[72] RPGI Initial Br. (I) at 5-7, 11-20; RPGI Initial Br. (II) at 12-23.

[73] RPGI Initial Br. (I) at 26-37; RPGI Initial Br. (II) at 29-40.

[74] RPGI Reply Br. (I) at 8; RPGI Reply Br. (II) at 7.

G. Alliant

30. Alliant supports Trial Staff's proposal to exclude the Expected Earnings model from the Commission's ROE methodology.[75] Alliant does not oppose the use of the DCF, CAPM or Risk Premium models in the Commission's ROE methodology.

H. Commission Determination

31. We will expand our methodology for determining whether an existing base ROE is unjust and unreasonable under the first prong of section 206, and for determining a new just and reasonable replacement base ROE under the second prong of section 206 when an existing ROE has been shown to be unjust and unreasonable, to rely on multiple financial models. Specifically, we will use the DCF model and CAPM in our ROE methodology, but not the Expected Earnings or Risk Premium models. As discussed further below, we find that expanding our methodology to use the CAPM model in addition to the DCF model will better reflect how investors make their investment decisions. This should result in our ROE analyses producing cost of equity estimates that more accurately reflect what ROE a utility must offer in order to attract capital. As discussed in sections VI and VIII below, we find that, on balance, the Expected Earnings and Risk Premium models would not improve our ROE determinations sufficiently to justify using those models, in light of their flaws and the potential inaccuracies and complexity that they could introduce into our ROE analyses.

32. As an initial matter, the D.C. Circuit has repeatedly observed that the Commission is not required to rely upon the DCF methodology alone or even at all.[76] Accordingly, the Commission may "change its past practices," such as relying exclusively on the DCF model, "with advances in knowledge in its given field or as its relevant experience and expertise expands," provided that it supplies "a reasoned analysis indicating that prior

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[75] Alliant Reply Br. at 5-7.

[76] *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1211 (D.C. Cir. 1991) (explaining that the Commission is free to reject the DCF methodology, provided that it adequately explains its reasons for doing so); *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1514 n.6 (D.C. Cir. 1984) ("[N]either statutes nor decisions of this court require that the Commission utilize a particular formula or a combination of formulae to determine whether rates are just and reasonable."); *NEPCO*, *Mun. Rate Comm. v. FERC*, 668 F.2d 1327, 1345 (D.C. Cir. 1987) ("FERC is not bound 'to the service of any single formula or combination of formulas.'" (quoting *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. at 586)); *see also Emera Maine*, 854 F.3d at 27 (noting that the Commission has authority to make "'pragmatic adjustments' to a utility's ROE" based on the facts of the particular case (quoting *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. at 586)).

policies and standards are being deliberately changed, not casually ignored."[77] Our existing ROE methodology relies on the DCF model exclusively for purposes of determining the zone of reasonableness that is used under the first and second prongs of section 206. However, we find that now, in light of our expanded experience with ROE determinations under various market conditions and the court's guidance in *Emera Maine*, expanding our ROE methodology to include the CAPM, as well as the DCF model, will better reflect how investors make their investment decisions and result in more accurate cost of equity estimates.

33. In *Hope*, the Supreme Court held that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[78] Thus, a key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, i.e., induce investors to invest in the utility in light of its risk profile.[79] As the Commission stated in Opinion No. 414-B,[80] "the cost of common equity to a regulated enterprise depends upon what the market expects not upon precisely what is going to happen."[81] Thus, in determining what ROE to award a utility, we must look to how investors analyze and compare their investment opportunities.

34. Investors have varying preferences as to which of the various methods for determining cost of equity they may use to inform their investment decisions. As Dr. Roger Morin states, "Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting

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[77] *Nuclear Energy Inst., Inc. v. EPA,* 373 F.3d 1251, 1296 (D.C. Cir. 2004) (per curiam) (internal citations and quotation marks omitted).

[78] *Hope*, 320 U.S. at 603. *See also Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) ("In order to attract capital, a utility must offer a risk-adjusted expected rate of return sufficient to attract investors.").

[79] *See Bluefield*, 262 U.S. at 692-693 (discussing factors an investor considers in making investment decisions).

[80] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

[81] *Id.* at 62,268. *See also Kern River Gas Transmission Co*., Opinion No. 486-B, 126 FERC ¶ 61,034, at P 120 (2009).

investor. There is no monopoly as to which method is used by investors."[82] As discussed further below, the record in this proceeding demonstrates that the CAPM model is one of the primary methods investors use to measure the cost of equity, along with the DCF model.[83] Moreover, like the DCF model, the CAPM model is market-oriented and produces a zone of reasonableness. Accordingly, we find that cost of equity estimates based on both models will provide a more reasonable measure of investor expectations, since they are among the information that investors rely upon when making investment decisions.

35. We also find that the expansion of our ROE methodology to use the CAPM in addition to the DCF model will help address the issues that led the court to remand Opinion No. 531 in *Emera Maine*. In that proceeding involving New England TOs' base ROE, the Commission found that it had "less confidence that the midpoint of the zone of reasonableness" produced by the DCF model "accurately reflect[ed] the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards."[84] Because of this concern, the Commission considered "'additional record evidence, including evidence of alternative benchmark methodologies" to inform the placement of ROE within the DCF-produced zone of reasonableness.[85] The Commission found that that evidence "supported a finding that an upward adjustment from the midpoint was warranted."[86] The

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[82] Roger A. Morin, *New Regulatory Finance* 429 (Public Utilities Reports, Inc. 2006) (Morin) at 429.

[83] *See, e.g.*, Trial Staff Initial Br. (I), Keyton Aff. at 11 ("the DCF, CAPM, and Risk Premium methods which are widely used by investors."); Trial Staff Initial Br. (II), Keyton Aff. (II) at 10 (stating same); MISO TOs Initial Br. (I) at 4 (explaining that the CAPM is "widely relied upon by investors"); MISO TOs Initial Br. (II) at 6 (explaining same); Trial Staff Reply Br. (I) at 5 ("'There are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in financial literature.'" (quoting San Diego Gas & Electric Company, Prepared Direct Testimony of Dr. Roger A. Morin on behalf of San Diego Gas & Electric Company, Docket No. ER19-221-000, at 16-17 (filed Oct. 30, 2018))); Michael C. Ehrhardt and Eugene F. Brigham, *Financial Management: Theory and Practice* 253 (13th ed. 2011) ("the basic CAPM is still the most widely used method for thinking about required rates of return on stocks.").

[84] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 49 (quoting Opinion No. 531, 147 FERC ¶ 61,234 at P 145).

[85] Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

[86] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 37.

Commission then set the New England TOs' ROE at the 10.57 percent midpoint of the upper half of the DCF zone of reasonableness. In taking this action, the Commission emphasized that it was "'not depart[ing] from [its] use of the DCF methodology.'"[87]

36. In *Emera Maine*, the court held that the Commission "failed to explain how any evidence demonstrated that 10.57 percent was a just and reasonable base ROE."[88] The court found that this omission was particularly troublesome in light of the Commission concerns over the reliability of the DCF zone of reasonableness. The court also stated that "FERC never explained how 10.57 percent was just and reasonable when the alternative benchmarks and additional record evidence it used to justify a departure merely pointed to a base ROE somewhere above 9.39 percent." The court also stated that "[o]n the one hand, [the Commission] argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57 percent base ROE."[89]

37. We find that if the most useful types of additional record evidence that the Commission relied upon in Opinion No. 531, namely the CAPM analysis, are more directly incorporated into the formal ROE methodology and construction of the zone of reasonableness, then that evidence will be directly "used to select" a just and reasonable ROE and we will not make ROE decisions because evidence "merely point[s] to a base ROE somewhere" that is different than a given base ROE, but because that evidence will be directly used to calculate a specific cost of equity estimate. This will help ensure that our ROE determinations are directly connected to, and supported by justifications in the record evidence. Our new ROE methodology will do this by averaging the top and bottom of the DCF and CAPM zones of reasonableness to produce a composite zone of reasonableness and then setting the ROE of average risk utilities at the central tendency midpoint of that zone.

38. Moreover, any methodology has the potential for errors or inaccuracies. Therefore, relying exclusively on any single methodology increases the risk that the Commission could authorize an unjust and unreasonable ROE. There is significant evidence indicating that combining estimates from different models is more accurate than relying on a single model.[90] For example, in discussing "model risk," Mr. McKenzie

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[87] Opinion No. 531, 147 FERC ¶ 61,234 at P 146.

[88] *Emera Maine*, 854 F.3d at 28.

[89] *Id.* at 28-29.

[90] *See, e.g.*, *In re. Connect Am. Fund*, 28 FCC Rcd. 7123, 7147 (2013) ("As the cost of equity reflects the uncertain expectations of investors, there is potential for introducing significant errors into the estimates, and no single model can be counted on

explained that "when conditions associated with a model are outside of the normal range, there is a risk . . . that the theoretical model will fail to predict or represent the real phenomenon that is being modeled."[91] Similarly, Ms. Ellen Lapson testified on behalf of MISO TOs that "it is wise to consider a broader set of evidence from alternate models and methods of estimating investors' cost of equity . . . Although all such methods are potentially subject to error, the use of multiple models that are based on different underlying assumptions provides a check on the reasonableness of the results of the DCF model and the placement of the [MISO TOs'] base ROE with the DCF range."[92]

39. As discussed further below, we find that the CAPM and DCF models most accurately reflect how investors make their investment decisions, therefore providing a more accurate cost of equity estimate and helping to minimize model risk to the greatest extent possible.

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exclusively to provide a precise estimate of the cost of equity."); *Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital*, STB Ex Parte No. 664 (Sub-No. 1), 2009 WL 197991, *11 (S.T.B. Jan. 23, 2009) ("As the Federal Reserve Board noted in its testimony in STB Ex Parte No. 664, academic studies had demonstrated that using multiple models will improve estimation techniques when each model provides new information. In addition, there is robust economic literature confirming that, in many cases, combining forecasts from different models is more accurate than relying on a single model.") (citations omitted); EL15-45-000, Ex. MTO-1 at 28 ("Rather, reference to the results of a number of well accepted methodologies provides greater clarity regarding the extent to which DCF results may be distorted, and the use of multiple benchmarks is useful in guiding the determination of a just and reasonable ROE within the zone of reasonableness.").

[91] Docket No. EL15-45-000, Ex. MTO-22 at 18-19 (citations omitted). *See also* Morin at 428 ("Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."); *id.* at 429-30 ("If a regulatory commission relies on a single cost of equity estimate or on a single methodology, that commission greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The results from one methodology . . . are likely to contain a high degree of measurement error and may be distorted by short-term aberrations.").

[92] Docket No. EL14-12-001, Ex. MTO-39 at 37.

IV. Presumptively Just and Reasonable ROE Ranges for Determining if an Existing ROE is Unjust and Unreasonable under Prong One of Section 206

A. Background

40. As noted above, in the Briefing Order, the Commission proposed to use ranges of presumptively just and reasonable ROEs in determining whether an existing ROE is unjust and unreasonable under the first prong of section 206.[93] As described below, CAPs and the RPGI oppose the Commission's proposed approach of using ranges of presumptively just and reasonable ROEs while MISO TOs support the proposal.

1. CAPs

41. CAPs contend that the Commission's proposed approach of establishing a range of presumptively just and reasonable ROEs would: (a) contravene the customer protection principles embodied in the FPA; (b) improperly tilt the balancing of interests under *Hope* and *Bluefield* in favor of industry over customers; (c) introduce an unlawful asymmetry between the treatment of FPA sections 205 and 206 filings; and (d) violate complainants' due process rights. In addition, they argue that the proposal to establish ranges of presumptively just and reasonable ROEs is arbitrary and capricious because it fails to provide a reasoned explanation for the risk profile.[94]

42. CAPs assert that *Emera Maine* did not hold or imply that the Commission must accept a range of ROEs as just and reasonable. They contend that, instead, it held that the Commission had not provided a sufficiently clear explanation of what made it unreasonable to retain a prior ROE that exceeded the newly re-determined cost of equity. In addition, they argue that the mere fact that the existing ROE was higher than the ROE determined to be just and reasonable was not the basis for the Commission's decisions in Opinion No. 551 and Initial Decision (II). They point out that both Opinion No. 551 and Initial Decision (II) found that the MISO TOs' existing 12.38 percent ROE was outside the DCF zone of reasonableness. CAPs accordingly argue that any concerns in *Emera Maine* with respect to the Commission's application of the first prong of section 206 where the existing ROE is within the DCF zone of reasonableness are not present in these proceedings.[95]

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[93] *See* Briefing Order, 165 FERC ¶ 61,118 at PP 24, 28-30.

[94] CAPs Initial Br. (I) at 67; CAPs Initial Br. (II) at 67.

[95] CAPs Initial Br. (I) at 68-69; CAPs Initial Br. (II) at 68-69.

43. CAPs argue that the Briefing Order presents its proposal to use ranges of presumptively just and reasonable ROEs as a response to the court's observation in *Emera Maine* that there exists a "broad range of potentially lawful ROEs."[96] CAPs contend that, however, nothing in *Emera Maine* requires the Commission to create ranges of presumptively just and reasonable ROEs. CAPs assert that the court held that the Commission was correct in noting that "rates within the zone of reasonableness are not *per se* just and reasonable" and that "the fact that a rate falls within the zone of reasonableness does not establish that the rate is *the* just and reasonable rate for the utility at issue."[97] CAPs contend that the *Emera Maine* court's reference to the "broad range of potentially lawful ROEs" was to the full breadth of the DCF range and that the court specifically affirmed that this range is not a zone of immunity from rate reductions under FPA section 206.[98]

44. In addition, CAPs assert that the proposal to use ranges of presumptively just and reasonable ROEs violates the Commission's statutory duty to protect customers from excessive rates because it would presume ROEs within the zone to be lawful even when the preponderance of the evidence points to a lower ROE. They argue that the just and reasonable standard of FPA sections 205 and 206 permits not even a little unlawfulness and that "the primary aim of the [FPA is] to guard the consumer against excessive rates."[99] CAPs contend that, accordingly, the customer protection purpose of section 206 requires the Commission to reduce existing rates that are shown to have become unjust, unreasonable, or unduly discriminatory, which conflicts with the use of ranges of presumptively just and reasonable ROEs.[100]

45. CAPs further argue that the use of ranges of presumptively just and reasonable ROEs would create an unlawful asymmetry between rate increases sought by utilities under FPA section 205 and rate reductions sought by consumers under FPA section 206. They contend that this would be the case because utilities filing under section 205 can continue to obtain approval of a proposed ROE increase if they show that the cost of

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[96] CAPs Initial Br. (I) at 70 (quoting *Emera Maine*, 854 F.3d at 26); CAPs Initial Br. (II) at 69 (quoting *Emera Maine*, 854 F.3d at 26).

[97] CAPs Initial Br. (I) at 70 (quoting *Emera Maine*, 854 F.3d at 23); CAPs Initial Br. (II) at 70 (quoting *Emera Maine*, 854 F.3d at 23).

[98] CAPs Initial Br. (I) at 71 (quoting *Emera Maine*, 854 F.3d at 23); CAPs Initial Br. (II) at 71 (quoting *Emera Maine*, 854 F.3d at 23) (emphasis added).

[99] CAPs Initial Br. (I) at 72; CAPs Initial Br. (II) at 72.

[100] CAPs Initial Br. (I) at 72-73; CAPs Initial Br. (II) at 72-73.

equity exceeds the existing ROE by any amount, but under the proposed presumption, customers filing complaints under section 206 would have to show that the existing ROE is so high that it is above the applicable range of presumptively just and reasonable base ROEs. CAPs assert that this treatment is contrary to the *Mobile*[101] and *Sierra*[102] cases and the 1988 Regulatory Fairness Act, all of which indicate that section 205 rate increase filings and section 206 complaints seeking rate decreases should be treated similarly. CAPs further contend that the use of ranges of presumptively just and reasonable ROEs will create an asymmetry between sections 205 and 206 by heightening the burden of proof faced by complainants under section 206.[103]

46. In addition, CAPs argue that the proposal creates a conclusive presumption that violates customers' due process rights. They contend that this is the case because the use of ranges of presumptively just and reasonable ROEs could allow an ROE to be considered presumptively just and reasonable even if the existing ROE exceeds the central value of all of the financial models that the Commission proposes to use. CAPs assert that the central values of the financial models are the best evidence of the cost of equity and if an ROE can exceed all of those values and still be considered presumptively just and reasonable, then the presumption is a conclusive presumption that violates customers' due process rights. CAPs argue that, while the Commission's Briefing Order indicates that the presumption can be rebutted with additional evidence to the contrary such as changes in capital market conditions, such changes in capital market conditions will already be reflected in the financial models and it is doubtful that customers will be able to produce additional evidence that is more effective than the collective evidence of the financial models. CAPs assert that the presumption is therefore effectively conclusive.[104]

47. CAPs also contend that the proposal to use ranges of presumptively just and reasonable ROEs is arbitrary and capricious. They argue that this is the case first because the proposed presumption is not inferred from proven facts, as is required by court precedent,[105] but rather from the erroneous conclusion that each of the MISO TOs is of average risk, combined with a logical fallacy. CAPs go on to contend that the

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[101] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956).

[102] *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

[103] CAPs Initial Br. (I) at 73-76; CAPs Initial Br. (II) at 73-75.

[104] CAPs Initial Br. (I) at 76-78; CAPs Initial Br. (II) at 76-78.

[105] CAPs Initial Br. (I) at 79 (citing *U.S. v. Gainey*, 380 U.S. 63, 78-79 (1965)); CAPs Initial Br. (II) at 78 (citing same).

Commission has not explained how the "broad range of potentially lawful ROEs" contemplated by *Emera Maine* becomes a range of presumptively just and reasonable ROEs. CAPs then assert that the Commission's rationale appears to be that an existing ROE is reasonable even if it exceeds (or is below) the risk-appropriate just and reasonable ROE as long as it is closer to the risk-appropriate ROE than to an appropriate ROE for a utility of a different risk profile.[106] They contend that this is arbitrary and capricious because the fact that an ROE lies closer to the just and reasonable ROE than to an appropriate ROE for a utility of a different risk profile does not render that ROE just and reasonable in light of court precedent that does not permit "even a little unlawfulness."[107] CAPs also argue that the proposal contradicts the court's rulings in *Emera Maine* that "[w]hether a rate, even one within the zone of reasonableness, is unlawful depends on the particular circumstances of the case" and that "the fact that a rate falls within the zone of reasonableness does not establish that the rate is the just and reasonable rate for the utility at issue."[108]

48. In addition, CAPs argue that it is arbitrary and capricious to assume that all utilities fall into one of only three risk groups—low risk, average risk, and high risk. They contend that the Commission has previously set ROEs at a wide variety of locations within the distribution of proxy results, not only at the upper or lower midpoint. CAPs suggest that the Commission could establish a greater number of more granular risk groups.[109]

2. MISO TOs

49. MISO TOs support the Commission's proposal in the Briefing Order to use the composite zone of reasonableness to identify a range of presumptively just and reasonable ROEs for utilities of similar risk profiles as an evidentiary tool to evaluate complaints under section 206 of the FPA. MISO TOs argue that it is well established that the Commission has the authority to adopt a rebuttable presumption to assist it in deciding whether or not to grant a complaint. They note that, in *AEP Marketing*,[110] the Commission described its authority to establish a new policy, including a new rebuttable

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[106] CAPs Initial Br. (I) at 79-80; CAPs Initial Br. (II) at 79.

[107] CAPs Initial Br. (I) at 80; CAPs Initial Br. (II) at 79-80.

[108] CAPs Initial Br. (I) at 80 (citing *Emera Maine*, 854 F.3d at 23); CAPs Initial Br. (II) at 80 (citing same).

[109] CAPs Initial Br. (I) at 82-83; CAPs Initial Br. (II) at 82-83.

[110] *AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018 (2004) (*AEP Marketing*).

presumption, as part of adjudication of a case-specific proceeding.[111] MISO TOs further state that the Commission adopted a rebuttable presumption that a "price squeeze" indicates that a wholesale rate is unduly discriminatory in violation of section 206 of the FPA[112] and the D.C. Circuit upheld this presumption.[113]

50. MISO TOs argue that it is immaterial whether the court in *Emera Maine* specifically mandated that the Commission use ranges of presumptively just and reasonable ROEs. They assert that the court in *Emera Maine* directed the Commission to provide a more complete explanation why the New England TOs' base ROE was unjust and unreasonable and that the Commission's adoption of ranges of presumptively just and reasonable ROEs is a logical step in analyzing whether an existing base ROE may no longer be just and reasonable under the first prong of FPA section 206. MISO TOs state that the Commission's adoption of a rebuttable presumption that a base ROE within a portion of the zone of reasonableness is consistent with *Emera Maine* and other ROE precedents which provide that there may be more than one just and reasonable return, even though the Commission ultimately must fix a single, just and reasonable rate.[114]

51. MISO TOs contend that the Commission's adoption of ranges of presumptively just and reasonable ROEs does not contravene the Regulatory Fairness Act. They assert that the Regulatory Fairness Act sought to add symmetry between FPA sections 205 and 206 by adding a refund obligation to FPA section 206 where previously there was none in order to match more closely the refund obligation in FPA section 205, but did not broadly require a uniform symmetry between sections 205 and 206 beyond what already existed between the two provisions. MISO TOs further argue that CAPs assume without basis that the Commission's ranges of presumptively just and reasonable ROEs will not apply in section 205 proceedings and that if the Commission does apply those ranges in section 205 proceedings, CAPs' concerns about symmetry between sections 205 and 206 are moot.[115]

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[111] MISO TOs Reply Br. (I) at 59-60 (citing *AEP Marketing*, 107 FERC ¶ 61,018 at PP 199, 201).

[112] MISO TOs Reply Br. (I) at 60 (citing *Conn. Light & Power Co.*, 8 FERC ¶ 61,187, at 61,655 (1979)).

[113] MISO TOs Reply Br. (I) at 60 (citing *Anaheim v. FERC*, 941 F.2d 1234, 1241, 1249 (D.C. Cir. 1991)).

[114] MISO TOs Reply Br. (I) at 61-63; MISO TOs Reply Br. (II) at 61-62.

[115] MISO TOs Reply Br. (I) at 64-65; MISO TOs Reply Br. (II) at 63-64.

52. MISO TOs also assert that CAPs erroneously attempt to characterize the presumption as conclusive or irrebuttable. MISO TOs state that CAPs purport to support their claim by arguing that the only evidence customers could possibly use to show a base ROE is unjust and unreasonable would be already incorporated into the Commission's calculation of the composite zone of reasonableness and the zone of presumptively just and reasonable ROEs. MISO TOs disagree and state that, for example, evidence that is not already incorporated in those zones could include risk premium data, which is used in the formulation of a new base ROE in prong two of FPA section 206 but not for calculation of the zone of reasonableness, non-utility stock prices and investor expectations for non-utility stocks, various types of bond yields, investor testimony and testimony of customer hardship.[116]

53. MISO TOs further argue that nothing about the approach of using ranges of presumptively just and reasonable ROEs contravenes the customer protection purpose of section 206. They contend that the approach will promote the Commission's compliance with its mandate to reduce existing rates only when they are shown to be unjust, unreasonable, or unduly discriminatory by providing an objective benchmark against which to measure existing rates. In addition, MISO TOs note that the rebuttable presumption provides value to customers and utilities alike, not only utilities as CAPs suggest. MISO TOs assert that a zone of presumptively just and reasonable ROEs is also a useful tool for making a *prima facie* case that an existing base ROE may no longer be just and reasonable, which will benefit consumers that file complaints.[117]

54. MISO TOs request that the Commission clarify that, just as a base ROE falling within the applicable quartile of the composite range of returns that is commensurate with the utility's risk profile creates a rebuttable presumption that such base ROE remains just and reasonable, a base ROE outside of the same quartile is only rebuttably presumed to be no longer just and reasonable.[118]

3. RPGI

55. RPGI argues that the proposed approach of using ranges of presumptively just and reasonable ROEs effectively shields existing ROEs from modification absent a showing that the ROE is outside the applicable range. RPGI asserts that no such margin applies to any other existing cost of service component of a formula rate like those employed by most transmission utilities under current Commission practice. RPGI contends that, if the cost of furnishing regulated service declines, it is subject to adjustment and true-up on an

[116] MISO TOs Reply Br. (I) at 67-68; MISO TOs Reply Br. (II) at 66-67.

[117] MISO TOs Reply Br. (I) at 68-69; MISO TOs Reply Br. (II) at 67-68.

[118] MISO TOs Initial Br. (I) at 6; MISO TOs Initial Br. (II) at 7-8.

annual basis under formula rates. RPGI contends that it is arbitrary and unfair to consumers to allow a zone of protection within which changes to a base ROE allowance will be disregarded, given the magnitude of the costs at issue. RPGI also contends that the Commission does not indicate that it intends to determine whether to dismiss a complaint and whether to grant a complaint on the basis of the same process. In addition, RPGI asserts that the Commission should clarify how it intends to resolve factual issues raised by the process in which a complaint and answer are filed. RPGI contends that, if the Commission anticipates that it will be in a position to resolve all factual issues instrumental to denying a complaint, then it should follow that it can resolve all issues relating to the establishment of a just and reasonable replacement ROE allowance where it finds that a complainant has satisfied that same standard.[119]

56. RPGI argues that the Commission should not clarify, as MISO TOs request, that if a base ROE falls outside the applicable quartile zone of presumptively just and reasonable ROEs, it is only rebuttably presumed to be no longer just and reasonable. RPGI contends that this would unfairly benefit utilities by giving them additional procedures to defend an existing ROE and would delay adjudication of just and reasonable rates.[120]

B. Commission Determination

1. Use of Presumptively Just and Reasonable ROE Ranges Generally

57. In *Emera Maine*, the court found that our prior practice of using "a single ROE analysis" to demonstrate both: (1) that an existing ROE is unjust and unreasonable under the first prong of FPA section 206; and (2) that a new ROE is just and reasonable under the second prong is contrary to the FPA.[121] In response to that decision, we adopt a new framework for evaluating whether an existing ROE remains just and reasonable for purposes of the first prong of FPA section 206. Specifically, we adopt the use of ranges of presumptively just and reasonable ROEs based on the risk profile of a utility or group of utilities to inform our decision of whether an existing ROE has become unjust and unreasonable, as proposed in the Briefing Order.[122] We reiterate that, for average risk utilities, the presumptively just and reasonable range is the quartile of the overall composite zone of reasonableness centered on the central tendency of the overall zone of

[119] RPGI Initial Br. (I) at 40-41; RPGI Initial Br. (II) at 43-44.

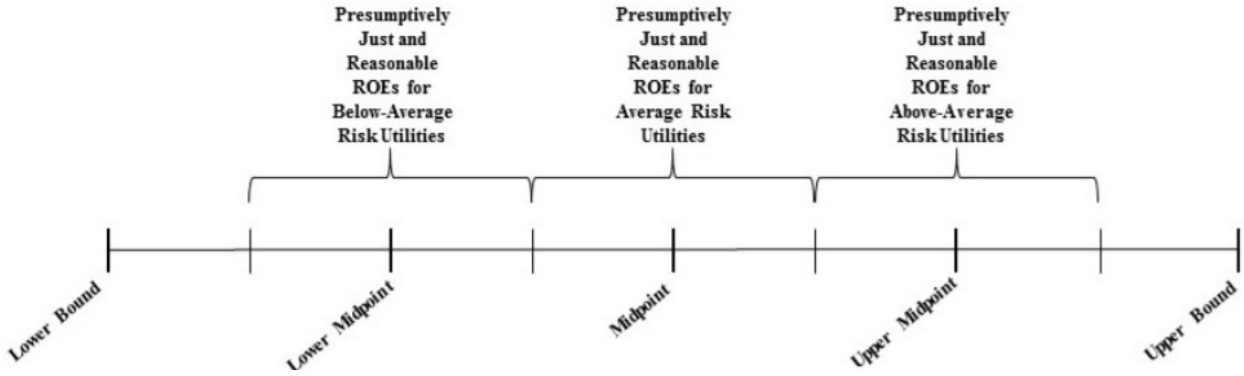
[120] RPGI Reply Br. (II) at 24-26.

[121] *Emera Maine*, 854 F.3d at 27.

[122] *See* Briefing Order, 165 FERC ¶ 61,118 at PP 17, 24, 28-30.

reasonableness; for below average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of reasonableness; and for above average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness. These ranges of presumptively just and reasonable located within the overall composite zone of reasonableness are again illustrated below.

Figure 1: Zone of Reasonableness Quartiles



58. We recognize that this facet of our new ROE methodology departs from our prior policy and precedent. As courts have held, "[t]he Commission can depart from a prior policy or line of precedent, but it must acknowledge that it is doing so and provide a reasoned explanation."[123] The D.C. Circuit has explained that

> [a]n agency is free to discard precedents or practices it no longer believes correct. Indeed we expect that any agency may well change its past practices with advances in knowledge in its given field or as its relevant experience and expertise expands. If an agency decides to change course, however, we require it to supply a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored.[124]

[123] *La. PSC v. FERC*, 772 F.3d 1297, 1303 (D.C. Cir. 2014) (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 57 (1983)).

[124] *Nuclear Energy Inst., Inc. v. EPA,* 373 F.3d 1251, 1296 (D.C. Cir. 2004) (per curiam) (internal citations and quotation marks omitted).

That same court has affirmed the Commission's departure from prior policy when the Commission has "explained how changed circumstances justified a new policy."[125] Similarly, agency action has been upheld where "to the extent the agency departed from precedent, it offered a reasonable explanation for doing so."[126]

59. We find that this change to our prior methodology for determining whether an existing ROE is unjust and unreasonable is necessary to ensure that our ROE determinations under section 206 satisfy the requirements of the *Emera Maine* decision. In that case, the court found that the Commission's decision that "a single ROE analysis generating a new just and reasonable ROE necessarily proved that the Transmission Owners' existing ROE was unjust and unreasonable" is contrary to the FPA.[127] The court found that this decision "relied on [the Commission's] assumption that all ROEs other than the one FERC identifies as the utility's just and reasonable ROE are per se unlawful in a section 206 proceeding."[128] However, the court held that, because "the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE," a finding that a particular ROE is just and reasonable, "standing alone, 'does not amount to a finding that every other rate of return'" is not just and reasonable.[129] Rather, the Commission must explain what circumstances render an existing ROE unjust and unreasonable in order to satisfy its burden of proof under the first prong of FPA section 206.[130]

60. As discussed in detail later in this order, the Commission has long based its decisions concerning just and reasonable ROEs for public utilities on the "current market cost of equity."[131] Accordingly, the starting point for determining whether a public utility's existing ROE has become unjust and unreasonable must be a consideration of

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[125] *ANR Pipeline Co. v. FERC,* 205 F.3d 403, 407 (D.C. Cir. 2000).

[126] *Busse Broad. Corp. v. FCC,* 87 F.3d 1456, 1458 (D.C. Cir. 1996).

[127] *Emera Maine*, 854 F.3d at 26.

[128] *Id.*

[129] *Id.* (quoting *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 857 (D.C. Cir. 1983)).

[130] *Id.*

[131] *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Order No. 420, FERC Stats. & Regs. ¶ 30,644 at 31,367 (1985) (cross-referenced at 31 FERC ¶ 61,168).

whether the current market cost of equity has changed since the existing ROE was established. For this purpose, we intend to use the DCF and CAPM financial models to establish a composite zone of reasonableness reflecting the current market cost of equity, as discussed below. However, neither of those models "conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically."[132]

61. Accordingly, while the results of these models "inform" our determination whether an existing ROE has become unjust and unreasonable, the models are too imprecise to "rigidly . . . determine" that issue.[133] The models can, at best, produce a general estimate of the current cost of equity. As a result, there is no single percentage current cost of equity that we can select from the zone of reasonableness that will demonstrate that all other ROEs within the zone of reasonableness are per se unjust and unreasonable. Put another way, as the court held in *Emera Maine*, the mere fact that the financial models now produce a cost of equity that is somewhat lower than the existing ROE is, "without any further explanation," insufficient to satisfy our burden under FPA section 206 to "prove that Transmission Owners' existing base ROE was unlawful."[134] Rather, the court requires that we explain the "particular circumstances" that support an explicit finding that the existing ROE has become unjust and unreasonable.[135]

62. Given the imprecise tools available to us for estimating the current cost of equity, we find that our explanation in such circumstances must include a showing that the existing ROE is now outside some range of potentially just and reasonable ROEs within the zone of reasonableness for the public utility at issue, in light of our estimate of the current market cost of equity, or alternatively, that other evidence convincingly demonstrates that the existing ROE is unjust and unreasonable despite it falling within that range. Given the Court's explanation that there is "'a substantial spread' of potentially reasonable rates,"[136] we believe that a range of potentially just and reasonable ROEs will likely be the best evidence of what is a just and reasonable ROE for the utility

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[132] Morin at 429.

[133] *Emera Maine*, 854 F.3d at 26.

[134] *Id.*

[135] *Id.* (quoting *Montana-Dakota Utilities Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951)).

[136] *Id.*

at issue. Therefore, we find that it is appropriate to treat an ROE that falls within that range as presumptively just and reasonable, unless other evidence is sufficient to rebut that presumption. We also find that the circumstance most relevant to determining that range is the utility's risk profile. As the Supreme Court explained in *Hope*, when describing what has become the standard for evaluating whether an ROE is just and reasonable under the FPA, a utility's ROE "should be commensurate with returns on investments in other enterprises *having corresponding risks*."[137] Indeed, the D.C. Circuit has explained that failing to consider a utility's risk profile, at least relative to the proxy group companies, can itself be arbitrary and capricious.[138] By the same token, an ROE—even one within the zone of reasonableness—that is *not* commensurate with the returns on investments in other enterprises having "corresponding risks" will not be just and reasonable. Accordingly, we find that, in order to explain the "particular circumstances" that support an explicit finding that the existing ROE has become unjust and unreasonable, we must determine the relevant utility's risk profile and then identify a range of presumptively just and reasonable ROEs within the overall zone of reasonableness for that utility based on its risk profile.

63. Consistent with the Commission's well-established policy on relative risk analysis, we find that the measure of central tendency for the entire zone of reasonableness should be the starting point for identifying the range within the overall zone of reasonableness that represents presumptively just and reasonable ROEs for utilities with an average risk profile.[139] Similarly, the starting points for identifying the ranges within the overall zone of reasonableness that represent presumptively just and reasonable ROEs for utilities with above or below average risk profiles should be the measures of central tendency of the upper and lower halves of the zone of reasonableness, respectively.[140] Logic dictates that the end points of those ranges should not be closer to the starting points for the ranges of

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[137] *Hope*, 320 U.S. at 603 (emphasis added); *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 698 (D.C. Cir. 2007) (discussing this standard in the context of whether rates are just and reasonable).

[138] *Petal Gas*, 496 F.3d at 700.

[139] *See, e.g.*, *Emera Maine*, 854 F.3d at 27 (citing *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1213 (D.C. Cir. 1991)) ("We have noted that the midpoint is a good 'starting place' for the placement of the ROE.").

[140] *See, e.g.*, *id.* at 30 (citing *Tenn. Gas Pipeline*, 926 F.2d at 1213) (where "the utility at issue was riskier than the proxy group . . . the midpoint of the upper half was 'an obvious place to begin.'"); *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, at PP 270, 273 (2017) (setting ROE at the "measure of central tendency of the lower half of the zone of reasonableness . . . Given [the utility's] low level of risk as compared to the proxy group.").

utilities with different risk profiles than they are to their own starting point. Applying those principles, we find that the range within the overall zone of reasonableness that best represents presumptively just and reasonable ROEs for average risk utilities is the quartile of the zone of reasonableness centered on the central tendency of the entire zone of reasonableness, while the ranges within the overall zone of reasonableness that best represent presumptively just and reasonable ROEs for above- and below- average utilities are the quartiles centered on the central tendencies of the upper and lower halves of the zone of reasonableness, respectively.

64. This is the reasoning underlying how we constructed the ranges of presumptively just and reasonable ROEs proposed in the Briefing Order. We are now changing our ROE methodology to incorporate these ranges of presumptively just and reasonable ROEs into our analysis of whether an existing ROE is just and reasonable. We do so in order to satisfy the court's requirements in *Emera Maine* that our section 206 analysis produce an "actual finding as to the lawfulness" of an existing ROE and that we "explain what circumstances" led to that finding. Along with the prevailing market conditions, a utility's risk profile is the most important circumstance to be considered in determining whether an existing ROE is unjust and unreasonable. Using the ranges of presumptively just and reasonable ROEs objectively and automatically incorporates risk profile into our ROE analysis so that we can ensure that we explain how this most important circumstance factors into our ROE determinations under section 206, as the court required in *Emera Maine*.

65. While previous Commission determinations under section 206 regarding ROEs may have made "actual finding[s] as to the lawfulness" of existing ROEs and sufficiently "explain[ed] what circumstances" led to those findings without the use of ranges of presumptively just and reasonable ROEs as we are adopting herein, we find that using such ranges is now necessary to ensure that our determinations meet the requirements of the court in the *Emera Maine* decision and is well within the Commission's "'considerable latitude in developing a methodology responsive to its regulatory challenge.'"[141] We believe that using such ranges incorporates a utility's risk profile into our ROE analysis in a concrete and objective way that will establish a direct connection between the most important circumstance of the case—a utility's risk profile—and our ultimate determination as to whether an existing ROE is unjust and unreasonable. In addition, because our determination of a utility's risk profile will lead to a rebuttable presumption of lawfulness or unlawfulness, our reasoning underlying that determination will largely "explain what circumstances" support our "actual finding as to the lawfulness" of the existing ROE. That is because, if the presumption is not rebutted, the reasoning underlying our risk profile determination will support our finding as to

[141] *Emera Maine*, 854 F.3d at 20 (citations and internal quotation marks omitted) (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 55 (D.C. Cir. 2014)).

lawfulness and, if the presumption is rebutted, we will have to explicitly explain how the other evidence rebuts the presumption and leads to our finding as to unlawfulness.

66. Moreover, while using ranges of presumptively just and reasonable ROEs is necessary to ensure that our ROE determinations under section 206 meet the requirements of the *Emera Maine* decision, we believe that it will also provide more general benefits to consumers and utilities. Specifically, "[r]atemaking . . . is not a science"[142] and the overall composite zone of reasonableness that is calculated under the revised methodology will still "create[] a broad range of potentially lawful ROEs rather than a single just and reasonable ROE."[143] In addition, it remains true under the new ROE methodology, as it did under our prior policy and precedent, that "[w]hether a rate, even one within the zone of reasonableness, is unlawful depends on the particular circumstances of the case."[144] Accordingly, while the overall composite zone of reasonableness informs the Commission's assessment of whether an existing ROE is unjust and unreasonable under section 206, potential complainants and respondents still face a substantial amount of uncertainty as to whether an existing ROE is unjust and unreasonable in light of the particular circumstances of the case.

67. We believe that using ranges of presumptively just and reasonable ROEs will provide additional certainty and predictability to parties because it will provide an additional objective indicator of whether an existing ROE may be unjust and unreasonable under section 206. This additional guidance should help potential complainants assess whether an existing ROE may be unjust and unreasonable and avoid expending time and resources on complaints that are not likely to succeed. Similarly, utilities will be able to better assess whether their existing ROEs are likely to be found unjust and unreasonable under section 206 and, if so, proactively file to reduce their ROEs in advance of complaints.

68. At the same time, we recognize that whether an existing ROE is unjust and unreasonable, even one that falls within the applicable range of presumptively just and reasonable ROEs, still "depends on the particular circumstances of the case."[145] Accordingly, if an existing ROE falls within the applicable range of presumptively just and reasonable ROEs, the presumption that the ROE is just and reasonable is a rebuttable presumption. Therefore, other evidence regarding the particular circumstances of the case can demonstrate that an existing ROE is unjust and unreasonable even if falls within

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[142] *Boston Edison Co. v. FERC*, 885 F.2d 962, 969–70 (1st Cir. 1989).

[143] *Emera Maine*, 854 F.3d at 26.

[144] *Id.* at 23.

[145] *Id.*

the applicable range of presumptively just and reasonable ROEs, such as evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, and testimony regarding the effects of rates on customers. We believe that employing a rebuttable presumption will provide additional certainty and transparency to parties while also not restricting the Commission's ability to consider the particular circumstances of the case, as required by applicable precedent.

2. Arguments Opposing the Use of Presumptively Just and Reasonable ROE Ranges

69. We are not persuaded by the arguments opposing the use of ranges of presumptively just and reasonable ROEs as proposed in the Briefing Order. CAPs argue that the court's holding in *Emera Maine* did not require that we "must accept a range of ROEs as just and reasonable."[146] CAPs' argument on this point is inapposite. If an existing ROE falls within the applicable range of presumptively just and reasonable ROEs, it does not mean that we "must accept" that ROE as just and reasonable nor do such ranges establish that every ROE within that range "must" be just and reasonable. As we discuss further below, if an existing ROE falls within the applicable range of presumptively just and reasonable ROEs, then it is only rebuttably presumed to be just and reasonable. That presumption may be rebutted by other evidence regarding the particular circumstances of the case and the Commission may find that an existing ROE is unjust and unreasonable even if it falls within the applicable range of presumptively just and reasonable ROEs.

70. CAPs further assert that the court in *Emera Maine* only held that the Commission "was required to do more than show that its single ROE analysis generated a new just and reasonable ROE and conclusively declare that, consequently, the existing ROE was per se unjust and unreasonable."[147] It is true that the court held this, but it further held that the Commission's analysis did not satisfy section 206 because it "failed to include an actual finding as to the lawfulness of Transmission Owners' existing base ROE"[148] and explained that such a finding should "explain what circumstances rendered Transmission Owners' existing rate unlawful."[149] The court also stated that the Commission's decision

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[146] CAPs Initial Br. (I) at 68; CAPs Initial Br. (II) at 68.

[147] CAPs Initial Br. (I) at 68 (citing *Emera Maine*, 854 F.3d at 15); CAPs Initial Br. (II) at 68 (citing same).

[148] *Emera Maine*, 854 F.3d at 27.

[149] *Id.* at 26.

"relied on its assumption that all ROEs other than the one FERC identifies as the utility's just and reasonable ROE are *per se* unlawful in a section 206 proceeding",[150] but explained that this reasoning was insufficient because "the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE, meaning that FERC's finding that 10.57 percent was a just and reasonable ROE, standing alone, 'did not amount to a finding that every other rate of return was not.'"[151] Similarly, the court explained that finding that a just and reasonable ROE would be a "'a numerical value below the existing numerical value'"[152] was "without any further explanation . . . insufficient to prove that Transmission Owners' existing base ROE was unlawful."[153] Thus, CAPs' quote of the *Emera Maine* case is accurate but incomplete. In light of this more complete context of the court's holding, we find that using ranges of presumptively just and reasonable ROEs in our ROE methodology is necessary in order to ensure that our ROE determinations under section 206 meet the requirements of the court's holding in *Emera Maine*.

71. In particular, using such ranges will produce a specific result from our risk profile determination—a rebuttable presumption—and then we will make an explicit finding as to whether the other evidence presented by the parties in the case has rebutted that presumption. This analysis will allow the Commission to "explain what circumstances" support our "actual finding as to the lawfulness" in a structured manner. Moreover, because risk profile is the particular circumstance most relevant to determining whether an existing ROE is unjust and unreasonable, using ranges of presumptively just and reasonable ROEs based on a utility's risk profile will ensure that the risk profile determination has a clear and significant connection to our ultimate finding as to lawfulness. We find that the use of ranges of presumptively just and reasonable ROEs in our ROE methodology ensures that our determinations satisfy the requirements of the *Emera Maine* decision.

72. CAPs also argue that using ranges of presumptively just and reasonable ROEs violates the Commission's statutory duty to protect customers from excessive rates because it would presume ROEs within the range to be lawful even when the

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[150] *Id.*

[151] *Id.* (citing *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 952–53 (D.C. Cir. 1983)).

[152] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 32).

[153] *Id.*

preponderance of the evidence points to a lower ROE.[154] RPGI makes a similar argument, asserting that the use of these ranges effectively shields existing ROEs from modification absent a showing that they fall outside of the applicable range.[155] We disagree. Using ranges of presumptively just and reasonable ROEs will not hinder the Commission's ability to protect customers from excessive rates or necessarily require a showing that the relevant ROE falls entirely outside of the applicable range. As explained above, we will use the range of presumptively just and reasonable ROEs as an additional tool to help inform our ROE analyses. The range of presumptively just and reasonable ROEs will provide an initial indication of whether an existing ROE may be unjust and unreasonable which we will consider along with all of the other evidence in the applicable record, including evidence addressing the particular circumstances of the case. The presumption that will apply if an existing ROE falls within the applicable range of presumptively just and reasonable ROEs is rebuttable. Accordingly, the Commission can still find that the ROE is unjust and unreasonable based upon the preponderance of the evidence, even if it falls within the applicable range of presumptively just and reasonable ROEs. Moreover, as the court held in *Emera Maine*, the mere fact the financial models now produce a cost of equity that is somewhat lower than the existing ROE is, "without any further explanation," insufficient to satisfy our burden under FPA section 206 to "prove that Transmission Owners' existing base ROE was unlawful."[156] Thus, contrary to CAPs' assertion, even if the evidence points to a lower ROE, this alone "without any further explanation" is insufficient to support a finding that the existing ROE is unjust and unreasonable.

73. In opposing our use of presumptively just and reasonable ROEs, CAPs contend that we should take the approach that the *Emera Maine* court specifically rejected. CAPs assert that the court in *Emera Maine* held that "at any given time and for the particular circumstances of each case, there is ultimately a *single ROE* level that *is* just and reasonable."[157] On the contrary, the court explicitly held that there is a "broad range of potentially lawful ROEs rather than a single just and reasonable ROE"[158] and reversed the Commission's finding that an existing ROE was unjust and unreasonable because it exceeded the single just and reasonable ROE that the Commission would have set. CAPs similarly argue that ranges of presumptively just and reasonable ROEs are unlawful

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[154] CAPs Initial Br. (I) at 72-73; CAPs Initial Br. (II) at 72-73.

[155] RPGI Initial Br. (I) at 40; RPGI Initial Br. (II) at 43.

[156] *Emera Maine*, 854 F.3d at 26.

[157] CAPs Initial Br. (I) at 71-72 (emphasis in original); CAPs Initial Br. (II) at 71 (emphasis in original).

[158] *Emera Maine*, 854 F.3d at 26.

because the Commission cannot allow returns "that exceed the cost-based level." However, the court in *Emera Maine* found that the Commission must do more than simply determine what the cost-based ROE is and then determine if the existing ROE is unjust and unreasonable based on whether it exceeds that cost-based level. Accordingly, we disagree with CAPs' apparent position that the Commission should continue to follow the approach that was reversed in *Emera Maine* of identifying the cost of equity and then finding that an existing ROE is unjust and unreasonable under prong one of section 206 if it exceeds that cost of equity.

74. CAPs also argue that our use of ranges of presumptively just and reasonable ROEs will create an unlawful asymmetry between rate increases sought by utilities under FPA section 205 and rate reductions sought by consumers under FPA section 206. According to CAPs, utilities filing under section 205 can continue to obtain approval of a proposed ROE increase if they show that the cost of equity exceeds the existing ROE by any amount, but under the proposed presumption, customers filing complaints under section 206 would have to show that the existing ROE is so high that it is above the applicable range of presumptively just and reasonable base ROEs.[159] We disagree that the use of ranges of presumptively just and reasonable ROEs will create any unlawful difference between our treatment of filings under section 205 and section 206. As an initial matter, "[t]he purpose of section 206 is 'quite different' from that of section 205"[160] and "[s]ection 206's procedures are 'entirely different' and 'stricter' than those of section 205."[161] As the D.C. Circuit has further explained, "[i]n contrast to section 206, section 205 'is intended for the benefit of the utility,'"[162] and the Commission "plays 'an essentially passive and reactive' role under section 205."[163] The court in *Emera Maine* further explained that "A utility filing a rate adjustment under section 205 must show that the adjustment is *lawful*. The proponent of a rate change under section 206, however, bears 'the burden of proving that the existing rate is *unlawful*.'"[164] We find that there is nothing unlawful about using ranges of

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[159] CAPs Initial Br. (I) at 73-75; CAPs Initial Br. (II) at 73-74.

[160] *Emera Maine*, 854 F.3d at 24 (quoting *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875 (D.C. Cir. 1984)).

[161] *Id.* (quoting *City of Anaheim, Cal. v. FERC*, 558 F.3d 521, 525 (D.C. Cir. 2009)).

[162] *Id.* (quoting *City of Winnfield v. FERC*, 744 F.2d at 875).

[163] *Id.* (quoting *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002)).

[164] *Id.* (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)).

presumptively just and reasonable ROEs to inform our analysis of whether an existing ROE has been shown to be unlawful under section 206. The showing that is required under section 206 differs from the showing that is required under section 205. Using ranges of just and reasonable ROEs will not change this fact. It remains the case that demonstrating that a proposed rate change is lawful under section 205 and demonstrating that an existing rate is unlawful under section 206 are two different standards. CAPs frame their argument as opposing the use of ranges of presumptively just and reasonable ROEs, but they are in fact taking issue with the different standards that apply to section 205 filings and section 206 complaints. We lack the authority to change those standards and our modification of the Commission's ROE methodology to use ranges of presumptively just and reasonable ROEs adheres to those standards.

75. In addition, we reiterate that customers filing complaints under section 206 do not necessarily have to show that the existing ROE is so high that it is above the applicable range of presumptively just and reasonable base ROEs in order to demonstrate that an existing ROE is unjust and unreasonable. As noted above, the presumption is a rebuttable one and whether an existing ROE falls within the applicable range is just one piece of evidence that the Commission will consider along with all of the evidence in a particular case.

76. In support of their argument, CAPs point to court precedent ruling that "[t]he statutory 'just and reasonable' standard is the same under section 205 and section 206."[165] However, the same court in *Emera Maine*, citing that same case, clarified that "while '[t]he just and reasonable lodestar is no loftier under section 206 than under section 205,' the showing required of FERC to exercise its section 206 authority to change an existing rate differs from anything required for FERC to approve a utility's proposed rate adjustment under section 205."[166] Therefore, precedent does not require the Commission's analysis under sections 205 and 206 to be the same. On the contrary, the statutes themselves *require* different showings and thus a different analysis by the Commission. The Commission's use of ranges of presumptively just and reasonable ROEs in reviewing complaints under section 206 will help it determine if an existing rate has been shown to be unjust and unreasonable and that does not create any unlawful asymmetry with its analysis under section 205.

77. CAPs' contention that the Commission's use of such ranges also contravenes the Regulatory Fairness Act, which modified FPA section 206(b) to provide the Commission

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[165] CAPS Initial Br. (I) at 74 (citing *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014)); CAPS Initial Br. (II) at 74 (citing same).

[166] *Emera Maine*, 854 F.3d at 24 (quoting *FirstEnergy*, 758 F.3d at 353) (internal quotation marks omitted).

some refund authority, is also unavailing. CAPs assert that this is the case because the Regulatory Fairness Act was intended to add symmetry between the Commission's treatment of section 205 rate increase filings and section 206 complaints seeking rate decreases.[167] However, a step to "add symmetry" between the sections does not mean that they are completely symmetrical. In fact, as discussed above "[s]ection 206's procedures are 'entirely different' and 'stricter' than those of section 205."[168]

78. The fact that the Commission's analysis under section 206 differs from its analysis under section 205 is not only consistent with the Regulatory Fairness Act but also mandated by the statutory language of sections 205 and 206. CAPs further assert that *Mobile* and *Sierra* support their argument because those cases provide that a rate increase filing made and suspended under FPA section 205 and a rate decrease complaint filed under FPA section 206 are both subject to the same "character" and "scope."[169] We are not persuaded by this contention because, as discussed above, "while '[t]he just and reasonable lodestar is no loftier under section 206 than under section 205,' the showing required of FERC to exercise its section 206 authority to change an existing rate differs from anything required for FERC to approve a utility's proposed rate adjustment under section 205."[170] It is consistent with *Mobile* and *Sierra* for the Commission to employ one analysis to determine if the required showing that an existing ROE is unjust and unreasonable has been made under the first prong of section 206 and a somewhat different analysis to determine if a showing has been made under section 205 that a proposed ROE is just and reasonable.

79. CAPs also argue that using ranges of presumptively just and reasonable ROEs heightens the burden of proof faced by complainants, thereby creating an unlawful asymmetry between the burden of proof that utilities must meet to raise rates under FPA section 205, and the burden of proof that customers must meet to obtain lower rates under FPA section 206.[171] We disagree. The change to our ROE methodology to utilize ranges of presumptively just and reasonable ROEs does not change the burden of proof that

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[167] CAPS Initial Br. (I) at 74-75; CAPS Initial Br. (II) at 74.

[168] *Emera Maine*, 854 F.3d at 24 (quoting *City of Anaheim v. FERC*, 558 F.3d at 525).

[169] CAPs Initial Br. (I) at 74 (citing *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp*., 350 U.S. 332, 341 (1956); CAPs Initial Br. (II) at 74 (citing same).

[170] *Emera Maine*, 854 F.3d at 24 (quoting *FirstEnergy*, 758 F.3d at 353) (internal quotation marks omitted).

[171] CAPs Initial Br. (I) at 75-76; CAPs Initial Br. (II) at 75.

parties face under section 205 or section 206. It is merely an objective benchmark that will be used in our overall analysis of base ROEs to help determine if an existing rate has been shown to be unjust and unreasonable under section 206. It remains the case, as it was before implementing this modification to our ROE methodology, that "[a] utility filing a rate adjustment under section 205 must show that the adjustment is *lawful*" while "[t]he proponent of a rate change under section 206, however, bears 'the burden of proving that the existing rate is *unlawful*.'"[172] The use of ranges of presumptively just and reasonable ROEs does not change these burdens. Those ranges will merely serve to inform our assessment of ROEs. The fact that our use of those ranges will involve employing a rebuttable presumption does not change the burdens that apply. As MISO TOs note, the Commission has previously adopted a rebuttable presumption in the context of section 206. For example, in *AEP Marketing*,[173] the Commission adopted a rebuttable presumption that a utility does not possess market power in generation if it passes two market power screens and a rebuttable presumption that a utility does have market power if it fails either screen.[174] The Commission explained that "[f]ailure of a screen will provide the basis for instituting a section 206 proceeding and will establish a rebuttable presumption of market power in the section 206 proceeding."[175] This presumption is now incorporated in the Commission's regulations.[176] The Commission also previously adopted a rebuttable presumption that a "price squeeze" indicates a wholesale rate is unduly discriminatory in violation of section 206 of the FPA.[177] Indeed, the use of rebuttable presumptions in the context of section 206 analyses does not create an unlawful asymmetry with section 205 as CAPs suggest. Complainants continue to bear the burden of proving that the existing rate is unlawful and this burden is unchanged regardless of whether the rebuttable presumption is triggered. The addition of the ranges of presumptively just and reasonable ROEs merely provides additional detail regarding

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[172] *Emera Maine*, 854 F.3d at 24 (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d at 1571).

[173] *AEP Power Mktg.,* 107 FERC ¶ 61,018.

[174] *See id.* P 37.

[175] *Id.* P 201.

[176] *See* 18 C.F.R. §35.37(c)(1) (2019).

[177] *See Conn. Light & Power Co.*, 8 FERC at 61,655 ("Based on the above, we conclude that given the establishment of a prima facie case of price discrimination and competition, it is reasonable from an administrative point of view to presume that there is a reasonable probability of an anticompetitive effect. The utility, of course, will have an opportunity to rebut this presumption.").

how a complainant must approach its effort to satisfying that burden. As MISO TOs note, the Commission has broad discretion over what weight to give evidence presented to it,[178] and our use of ranges of presumptively just and reasonable ROEs merely provides additional detail as to our evidentiary expectations for complainants' satisfying the burden of proof under prong one of FPA section 206.

80. CAPs further contend that, at worst, the use of such ranges creates a conclusive presumption that violates customers' due process rights. They argue that this is the case because the central values of the financial models are the best evidence of cost of equity but the ranges of presumptively just and reasonable ROEs would allow an existing ROE to exceed the central values of all of the financial models and still be presumed just and reasonable. CAPs assert that it would violate their due process rights to presume the lawfulness of rates that have been shown to be excessive by the same financial models that are used to establish the range of presumptively just and reasonable ROEs. They argue that this is further true because it is doubtful that customers will be able to produce additional evidence that is more effective than the collective evidence of the financial models.[179] This argument is unavailing. As discussed above, the presumption that will apply if an ROE falls within the applicable range of presumptively just and reasonable ROEs is a rebuttable presumption. Contrary to CAPs' suggestion, there is a wide variety of potential additional evidence that could be used to rebut the applicable presumption. For example, complainants could offer evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, and investor and other expert testimony, including testimony regarding the effects of rates on customers. Moreover, even if an ROE falls within the applicable range of presumptively just and reasonable ROEs, the relative location of that ROE within the range, and the level of the ROE relative to the central values of the other financial models could be relevant. Accordingly, it is not the case, as CAPs imply, that the central values of the financial models would be ignored merely because an ROE falls within the applicable range of presumptively just and reasonable ROEs. These are just illustrative examples of the types of evidence that could be used to potentially rebut the presumption. There is a wide array of potential evidence that could be used to rebut the presumption and therefore we disagree with CAPs' contention that the presumption is conclusive.

81. CAPs also argue that the proposal to use ranges of presumptively just and reasonable ROEs is arbitrary and capricious because the proposed presumption is not

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[178] *See e.g., Hope*, 320 U.S. at 622 ("The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.").

[179] CAPs Initial Br. (I) at 76-78; CAPs Initial Br. (II) at 76-78.

inferred from proven facts. We disagree. The presumption is inferred from proven facts, namely the zones of reasonableness produced by the DCF and CAPM which use verifiable data inputs, the objective calculations of the overall composite zone of reasonableness, where the applicable range of presumptively just and reasonable ROEs is located within that overall zone, the identification of where the relevant existing ROE falls within that overall zone, and the determination of whether it falls within the applicable range of presumptively just and reasonable ROEs.

82. Moreover, we disagree with CAPs' contention that the rationale underlying how the ranges of presumptively just and reasonable ROEs are constructed is flawed. CAPs point to the Commission's statement in the Briefing Order that "for an average risk utility, the 'broad range of potentially lawful ROEs' that the D.C. Circuit contemplated in *Emera* should correspond to those points that are closer to the ROE that the Commission would set for that utility than to the ROE for a utility of a different risk profile,"[180] and then assert that the Commission has not explained how the potentially lawful ROEs contemplated in *Emera Maine* for the DCF zone of reasonableness became presumptively lawful ROEs under its new proposal. As an initial matter, we clarify that the ranges of presumptively just and reasonable ROEs are not coextensive with the "broad range of potentially lawful ROEs" contemplated in *Emera Maine*. As the court explained "the zone of reasonableness creates a broad range of potentially lawful ROEs."[181] The court was referencing the overall zone of reasonableness and we clarify that, under our revised methodology, the composite overall zone of reasonableness will still represent the "broad range of potentially lawful ROEs" for a utility or group of utilities. The ranges of presumptively just and reasonable ROEs are intended to assist the Commission, as well as market participants, in determining whether an ROE that falls within the overall composite zone of reasonableness is just and reasonable because "[w]hether a particular rate within the zone is the just and reasonable rate for the utility at issue depends on a number of factors" and "[t]hus, the fact that a rate falls within the zone of reasonableness does not establish that the rate is the just and reasonable rate for the utility at issue."[182] Accordingly, we clarify that the potentially lawful ROEs contemplated in this language of *Emera Maine* are not coextensive with the applicable range of presumptively just and reasonable ROEs under our revised methodology. As a result, CAPs' argument on this point does not demonstrate any flaw in our methodology.

83. CAPs also point to the Commission's statement in the Briefing Order that the applicable range of presumptively just and reasonable ROEs for a diverse group of

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[180] Briefing Order, 165 FERC ¶ 61,118 at P 29.

[181] *Emera Maine*, 854 F.3d at 26.

[182] *Id.* at 23.

average risk utilities is one quarter of the zone of reasonableness, centered on the midpoint because "[e]very potential ROE within that range is closer to the current just and reasonable ROE for an average-risk utility than the current just and reasonable ROE for a utility of a different risk profile."[183] CAPs counter that the observation that an ROE lies closer to the just and reasonable ROE than to some appropriate ROE for a utility of a different risk profile does not render that ROE just and reasonable. CAPs have misconstrued the point of the statement. Nothing in our rationale asserts the position CAPs describes. The fact that an ROE lies closer to the just and reasonable ROE than to an appropriate ROE for a utility of a different risk profile does not render that ROE just and reasonable, but it does provide some evidence indicating that the ROE may be just and reasonable. That is why our revised methodology uses that information to determine how to construct the ranges of presumptively just and reasonable ROEs, which we will then use as one piece of evidence in our overall assessment of whether an ROE is just and reasonable. Our rationale does not find that this information conclusively establishes that an ROE is just and reasonable, but instead that it is some evidence indicating that the ROE is just and reasonable. Using this information to construct the ranges of presumptively just and reasonable ROEs is the most effective manner in which we can incorporate this information into our ROE methodology.

84. In addition, CAPs argue that the use of only three risk groups (below-average risk, average risk, and above-average risk) in the ranges of presumptively just and reasonable ROEs is arbitrary. They assert that the Commission has previously set ROEs at a wide variety of locations within the distribution of proxy results, not only at the upper or lower midpoint. CAPs suggest that the Commission could establish more granular risk groups, for example using five risk groups of very-low-risk, moderately-low-risk, average-risk, moderately-high-risk, and very-high risk. We are not persuaded by this argument. The quartile approach using three risk groups strikes an appropriate balance between the interests of customers and utilities. We find that the ranges that are produced by this approach are narrow enough to protect customers from unjust and unreasonable ROEs while also providing utilities and all market participants with an additional objective benchmark that the Commission will use to assess whether an ROE is likely unjust and unreasonable. This will provide additional transparency and certainty with respect to our ROE analyses without giving undue preference to a utility's existing ROE or to a challenge of an existing ROE. As noted above, the use of three risk groups is supported by the fact that, under that construct, every ROE within the applicable presumptively just and reasonable range will be closer to the traditional starting place for evaluating the

[183] CAPs Initial Br. (I) at 79-80 (citing Briefing Order, 165 FERC ¶ 61,118 at P 29); CAPs Initial Br. (II) at 79 (citing same).

ROE of a utility with that risk profile[184] than it will be to the corresponding traditional starting place for a utility of a different risk profile. This approach will most effectively identify whether a given ROE is likely more appropriate for a utility of the applicable risk profile than it would be for a utility of a different risk profile, which will help inform our assessment of whether the ROE is unjust and unreasonable in light of all of the particular circumstances of the case. Because "[r]atemaking . . . is not a science,"[185] we could have constructed the ranges of presumptively just and reasonable ROEs using a different number of risk groups or with wider or narrower ranges.[186] However, we find that, in light of the record in these proceedings and our past experience with ROE analyses, the approach we are adopting herein will best balance the interests of consumers and utilities and most effectively allow us to determine if an ROE is unjust and unreasonable.

85. MISO TOs request that the Commission clarify that a base ROE that falls outside of the applicable range of presumptively just and reasonable ROEs is only rebuttably presumed to be no longer just and reasonable, just as an ROE that falls within the zone is only rebuttably presumed to be just and reasonable.[187] RPGI opposes this clarification, arguing that it would unfairly benefit utilities.[188] We clarify that the Commission will apply a rebuttable presumption to both ROEs that fall within the applicable range of presumptively just and reasonable ROEs and those that fall outside of the applicable range. In other words, ROEs that fall within the applicable range will be presumed to be just and reasonable, unless that presumption is rebutted, and those that fall outside of the applicable range will be presumed to be unjust and unreasonable, unless that presumption is rebutted.

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[184] *See, e.g.*, *Emera Maine*, 854 F.3d at 27 ("We have noted that the midpoint is a good 'starting place' for the placement of the ROE.") (citing *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1213 (D.C. Cir. 1991)); *id.* at 30 (where "the utility at issue was riskier than the proxy group . . . the midpoint of the upper half was 'an obvious place to begin.'") (citing *Tenn. Gas Pipeline*, 926 F.2d at 1213); *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, at PP 270, 273 (2017) (setting ROE at the "measure of central tendency of the lower half of the zone of reasonableness . . . Given [the utility's] low level of risk as compared to the proxy group.").

[185] *Boston Edison Co. v. FERC*, 885 F.2d 962, 969-70 (1st Cir. 1989).

[186] *See, e.g.*, CAPs Initial Br. (I) at 82-83 (proposing five risk groups with sextiles within the composite zone applying to each group).

[187] MISO TOs Initial Br. (I) at 6; MISO TOs Initial Br. (II) at 7-8.

[188] RPGI Reply Br. (II) at 24-26.

86. RPGI requests that the Commission acknowledge that it intends to determine whether to dismiss a complaint and whether to grant a complaint on the basis of the same process under the new ROE methodology. Specifically, RPGI contends that, if the Commission anticipates that it will be in a position to resolve all factual issues instrumental to denying a complaint if the relevant ROE falls within the applicable range of presumptively just and reasonable ROEs and the presumption is not rebutted, then the Commission should apply an equivalent standard for granting complaints.[189] We clarify that we intend to determine whether to dismiss a complaint and whether to grant a complaint on the basis of the same process under the new ROE methodology. The ranges of presumptively just and reasonable ROEs and the other changes to our methodology adopted in this order will apply generally to our overall assessment of existing ROEs under FPA section 206. There will be no difference in how the methodology is applied in the context of potentially dismissing a complaint as opposed to potentially granting a complaint, outside of the differences in the statutory and regulatory burdens and requirements that complainants and respondents face under section 206 which, as noted above, the revised methodology adopted herein cannot and does not change. With respect to RPGI's contention that, if the Commission anticipates that it will be able to resolve all factual issues relevant to denying a complaint, it should also be able to do so with respect to granting a complaint, we clarify that we do not necessarily anticipate that the revised methodology adopted in this order will allow us to resolve all factual issues in every ROE case without additional hearing or settlement procedures. As was the case before this order, there may be cases where we will be able to resolve all factual issues before us and dismiss or grant a complaint without additional procedures. However, there may be other cases where there are issues of material fact in dispute that cannot be resolved based upon the record and will require additional procedures. We will not approach the question of whether there are issues of material fact differently in determining if a complaint will be granted as opposed to if a complaint will be denied, again outside of the differences in the statutory and regulatory burdens and requirements that complainants and respondents face under section 206 which the revised methodology adopted herein does not change.

V. DCF

A. Background

87. The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk. With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price:

[189] RPGI Initial Br. (I) at 41; RPGI Initial Br. (II) at 44.

$$P = D/k-g,$$

where "P" is the price of the common stock, "D" is the current dividend, "k" is the discount rate (or investors' required rate of return), and "g" is the expected growth rate in dividends.

88. Unlike investors, the Commission uses the DCF model to determine the ROE (the "k" component) to be included in the utility's rates, rather than to estimate a stock's value. Therefore, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock. The Commission also multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield." Under the resulting formula, ROE equals the adjusted dividend yield plus the expected future growth rate of dividends and can be expressed as follows:

$$k=D/P\ (1+.5g) + g.$$

89. Under the Commission's two-step DCF methodology, the input for the expected future growth rate of dividends, "g," is calculated using both short-term and long-term growth projections.[190] Those two growth rate estimates are averaged, with the short-term growth rate estimate receiving two-thirds weighting and the long-term growth rate estimate receiving one-third weighting, to create a composite growth rate.[191]

B. Dividend Yield

90. In the First Complaint proceeding, all parties, including the MISO TOs, calculated the adjusted dividend yield using the same composite growth rate, including both short- and long-term growth rates, for the (1+.5g) adjustment the Commission uses for the expected future growth rate of dividends. Accordingly, the Presiding Judge in that proceeding, and the Commission in Opinion No. 551, also calculated the adjusted dividend yield using the composite growth rate, and no party sought rehearing of Opinion No. 551 on this issue.

91. Initially, all parties in the Second Complaint proceeding, including the MISO TOs, also proposed to calculate the adjusted dividend yield using the composite growth rate for

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[190] Opinion No. 531, 147 FERC ¶ 61,234 at PP 15-17, 36-40; Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[191] Opinion No. 531, 147 FERC ¶ 61,234 at PP 17, 39.

the (1+.5g) adjustment. However, three days after the MISO TOs filed their update testimony in the Second Complaint proceeding, the Commission issued Opinion No. 546 in *Seaway Crude Pipeline Co. LLC*,[192] holding that only a short-term growth projection should be used in calculating the (1+.5g) adjustment to dividend yield. The Commission stated that "the short-term IBES growth rate is far more representative of the growth investors expect over the coming year than is the [composite] growth rate."[193] At the hearing in the Second Complaint proceeding, the MISO TOs presented modified dividend yield calculations consistent with Opinion No. 546, using only short-term growth projections to calculate the (1+.5g) adjustment to dividend yield.[194] However, the Presiding Judge, without discussion, used the same composite growth rate to calculate the adjusted dividend yield as used for the expected future growth in dividends.

1. MISO TOs

92. In their brief on exceptions to Initial Decision (II) in the Second Complaint proceeding and in the initial affidavits of their witness Mr. McKenzie in response to the Briefing Order, MISO TOs argue that only the short-term IBES growth rate should be used to calculate the (1+.5g) adjustment to dividend yield. They point out that the Commission found in Opinion No. 546 that a projected GDP growth rate should not be used in adjusting the dividend yield, because the short-term IBES growth rate is more representative of the growth investors expect over the coming year than a composite growth rate also reflecting GDP growth.[195] In their brief on exceptions, MISO TOs explain that the Commission has long held that "[t]he appropriate dividend figure to use in the DCF equation is the amount which is expected to be received by the investor during the twelve months following the purchase of the stock."[196] MISO TOs assert that the Commission assumes that the dividend will be increased annually and that the next increase will occur on average six months after the stock purchase.[197] Therefore, the

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[192] *Seaway Crude Pipeline Co.*, Opinion No. 546, 154 FERC ¶ 61,070, at PP 198-200 (2016).

[193] *Id*. P 198.

[194] Ex. MTO-140 (II). Tr. 310-311 (II).

[195] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 17-18; MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 18-19; MISO TOs Br. On Exceptions at 38-44.

[196] *Id*. at 42 (quoting *Conn. Light & Power Co.*, Opinion No. 305-A, 45 FERC ¶ 61,370, at 62,168-69 (1988)).

[197] *Id*. at 40 (citing Opinion No. 305-A, 45 FERC at 62,169).

actual dividend yield during the six-month study period must be adjusted upward for the first expected dividend increase. MISO TOs state that, because the adjusted dividend yield is intended to reflect investor expectations during just one year, it is inherently a short-run figure, and therefore the short-term IBES growth projection is the appropriate growth projection to use in making the adjustment.

2. CAPs

93. CAPs oppose MISO TOs recommendation to use only a short-term dividend growth rate, for purposes of the (1+ .5g) adjustment to the dividend yield.[198] Instead, they recommend using a composite growth rate consistent with Opinion Nos. 531 and 551 and Initial Decision (II).

94. CAPs contend that the Commission's longstanding practice has been to use the composite growth rate, not the short-term IBES growth projection, as the "g" in the (1 + .5g) dividend adjustment factor.[199] They state that this practice is appropriate, because the purpose of the adjustment is to account for the quarterly, rather than annual, payment of dividends, and therefore the adjustment requires a projection of growth in dividends, not growth in earnings. CAPs state that projected long-term earnings growth is the best available predictor of near-term dividend growth because: (1) long-term earnings growth funds long-term dividend growth; and (2) utility holding companies moderate their near-term dividend growth in order to avoid cutting dividends when earnings fall. Thus, CAPs claim, "the composite growth rate is a better predictor of near-term dividend yield increases than is the first-stage growth rate."[200] CAPs state that this conclusion is borne out in the record of the Second Complaint proceeding, where, to take one example, OGE Energy's earnings have increased during the last five years by 6.84 percent annually, but its dividends have only increased by 4.5 percent annually.[201]

95. CAPs also reject the MISO TOs' argument that Opinion No. 546 established a new DCF methodology for electric utilities. Rather, CAPs state that Opinion No. 546 concerned an oil pipeline master limited partnership (MLP) and was a "case-specific determination" that the pipeline's DCF study should not be disregarded because of a relatively minor difference related to the dividend adjustment. CAPs point out that the

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[198] CAPs Reply Br. (I) at 22-25; CAPs Reply Br. (II) at 40-44; CAPs Br. Opposing Exceptions at 40-44.

[199] CAPs Reply Br. (I) at 23. CAPs Reply Br. (II) at 42.

[200] CAPs Reply Br. (I) at 23; CAPs Reply Br. (II) at 42.

[201] CAPs Br. Opposing Exceptions at 43.

pipeline had argued that, for MLPs, the short-term earnings growth rate was the best predictor of the coming year's earnings growth, because MLPs distribute most available cash to investors, and therefore near-term dividends growth would be expected to track near-term earnings growth. CAPs assert that this determination in Opinion No. 546 was never meant to apply to electric utilities.[202] In addition, CAPs argue that the MISO TOs' recommended methodology of using different growth rates for future dividends and cash flows would distort the DCF model's results.[203]

3. Trial Staff

96. Trial Staff also opposes using only a short-term dividend growth rate, for purposes of the (1+ .5g) adjustment to the dividend yield. Trial Staff contends that MISO TOs' reliance on Opinion No. 546 is misplaced. Trial Staff states that that case involved an oil pipeline and used a proxy group of only oil pipeline MLPs, which "distribute most available cash to investors."[204] Trial Staff instead asserts that "investors value stable dividends" and that "adjusted dividend yield calculations should be based on expectations of long-term earnings growth, which requires the use of the composite growth rate."[205]

97. Trial Staff also contends that, if the Opinion No. 546 dividend adjustment methodology is applied to public utilities, it is likely to reduce the low-end DCF results and increase the high-end DCF results. That is because proxy companies with high-end DCF results generally have IBES growth rates that are higher than the GDP growth projection, while proxy companies with low-end DCF results have IBES growth projections that are less than the GDP growth projection. However, Trial Staff states that the reduced low-end DCF results are likely to be eliminated by the low-end outlier test, but the high-end results will not be eliminated. As a result, Trial Staff asserts that the Opinion No. 546 methodology is likely to increase the midpoint ROE.[206]

4. Commission Determination

98. The Commission will use the short-term growth rate to calculate the (1+.5g) adjustment to dividend yield. As noted in Opinion No. 305-A,

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[202] *Id.* at 41-42.

[203] CAPs Reply Br. (I) at 22-24; CAPs Reply Br. (II) at 41-43.

[204] Trial Staff Reply Br. (I) at 8; Trial Staff Reply Br. (II) at 8.

[205] Trial Staff Reply Br. (I) at 9; Trial Staff Reply Br. (II) at 9.

[206] Trial Staff Br. Opposing Exceptions at 20-21.

> The appropriate dividend figure to use in the DCF equation is that amount which is expected to be received by the investor during the twelve months following the purchase of the stock. To estimate that amount, we generally make the following two simplifying assumptions: (a) that the dividend rate will be increased annually (this has been the recent practice for electric utilities); and (b) that the next increase will occur, on average, six months after the stock purchase.[207]

Because this first dividend is necessarily paid within the time period covered by the IBES short-term growth projection, that rate is the more appropriate growth rate for calculating the (1+.5g) adjustment to the dividend yield.

99. We are not persuaded by the contention that the Commission should apply Opinion No. 546 only to oil pipeline MLPs. Opinion No. 546 approved use of the short-term IBES growth projection to calculate the (1+.5g) adjustment to dividend yield on the ground that "the short-term IBES growth rate is far more representative of the growth investors expect over the coming year than is the two-stage growth rate."[208] That rationale applies equally to public utilities as to oil pipelines. It does not turn on any unique feature of oil pipeline MLPs, such as their slower expected long-term growth because of the fact MLPs distribute most available cash to investors. We find that the adjusted dividend yield methodology used in Opinion No. 546 should be applied both to electric utilities and pipeline companies. Furthermore, we do not agree that using different growth rates would distort the DCF's results; the adjusted dividend yield, which concerns only the dividend received in the first year after a stock's purchase, is logically distinct from the infinite stream of dividends received from holding the stock in perpetuity.

100. We do not find Trial Staff's assertion that using only the IBES growth rate in calculating the adjusted dividend yield is likely to increase the midpoint ROE to be a basis for requiring the composite growth rate to be used in calculating the adjusted dividend yield. As noted above, the adjusted dividend yield only considers expected growth within the year after a stock's purchase, and so should be calculated using a short-term growth rate. In any event, as the Commission stated in Opinion No. 546, using only the IBES short-term growth projection to make the (1+.g) adjustment to dividend yield has a *de minimis* effect on the outcome of the DCF analysis, increasing proxy company ROEs by only one or two basis points.

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[207] Opinion No. 305-A, 45 FERC ¶ 61,370 at 62,168-69.

[208] Opinion No. 546, 154 FERC ¶ 61,070 at P 198.

C. Short-Term Growth Rate

1. Opinion No. 551

101. In the First Complaint proceeding, the MISO TOs proposed to use earnings growth projections published by *Value Line* as the short-term projection of the future growth in dividends. However, the Presiding Judge adopted the IBES 3 to 5 year growth projections published by *Yahoo! Finance*, stating that the Commission has "long relied on IBES growth projections as evidence of the growth rates expected by the investment community."[209] Additionally, the Presiding Judge stated that the Commission's policy that ROE should be determined using the most recent financial data in the record (i.e., data for the last six months of 2015) dictates use of the IBES growth projections, because the MISO TOs had only provided *Value Line* data from the first half of 2015, whereas the other parties had provided IBES growth projections through July 13, 2015.[210] In their brief on exceptions, MISO TOs stated they were not excepting to the Presiding Judge's use of IBES growth projections in the First Complaint proceeding, because the record did not contain *Value Line* growth estimates from the last half of 2015. However, they requested that the Commission confirm that, in future proceedings, *Value Line* growth projections would constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis.[211]

102. In Opinion No. 551, the Commission denied MISO TOs' request for clarification that the *Value Line* growth projections constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis. It stated, that while the Commission has not mandated the exclusive use of IBES data in its natural gas and oil pipeline rate of return cases, the Commission has stated that "IBES data is the preferred data source for computing the short-term growth rate"[212] and explained that "IBES data is a compilation of projected growth rates from

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[209] Initial Decision (I), 153 FERC ¶ 63,027 at PP 44, 46.

[210] *Id.* PP 48-49.

[211] *See* Opinion No. 551, 156 FERC ¶ 61,234 at PP 46-53.

[212] *Nw. Pipeline Corp.*, 92 FERC ¶ 61,287, at 62,002 (2000). *See also Nw. Pipeline Corp.*, 79 FERC ¶ 61,309, at 62,385 (1997) (finding that "[t]he IBES figures should be used for the short-run growth rate of reach of the proxy companies.").

various knowledgeable financial advisors within the investment community."[213] As such, the IBES short-term growth estimates generally represent consensus growth rate estimates by a number of analysts. The Commission stated that, by contrast, it has rejected the use of *Value Line* growth estimates, because they are the estimates of a single analyst and do not constitute such consensus estimates.[214]

103. In response to MISO TOs' argument that the *Value Line* estimates should be considered a comparable source, the Commission cited Opinion No. 531, which states that the Commission "has long relied on IBES growth projections as evidence of the growth rates expected by the investment community."[215] The Commission also noted that Opinion No. 531 states that, while the Commission could conceivably allow the substitution of "comparable data," an "alternative source of growth rate data should only be used when that source can be used for the growth projections of all of the proxy group companies" because using different sources could "produce skewed results, because those sources may take different approaches to calculating growth rates."[216] The Commission confirmed that this is the reason that it has "consistently used a single investor service such as IBES for the investment analysts' growth rate estimates."[217]

104. Thus, the Commission stated that, while it is willing to use short-term growth data published by a source comparable to IBES, because *Value Line* does not publish consensus growth rate estimates, it cannot be considered comparable.[218] The Commission also stated that published consensus estimates sourced from investment

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[213] *See, e.g.*, *Nw. Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,058-59 (1999); *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 234 (2002).

[214] Opinion No. 551, 156 FERC ¶ 61,234 at P 62 (citing *Nw. Pipeline Corp.*, 87 FERC at 62,058-59; *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 234; Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72 n.145 (stating that the *Value Line* data "for any company consists of an earnings estimate from only one analyst, rather than consensus estimates")).

[215] *Id.* P 63 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 89-90).

[216] *Id.* (citing *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004) (finding that a presiding judge is not precluded from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by IBES or *Value Line*)).

[217] *Id.*

[218] *Id.* P 64.

analysts, e.g., IBES's growth rate estimates, are updated on a rolling basis, sometimes as frequently as daily, and are therefore superior to *Value Line*'s growth rate estimates, which are updated only on a lagging, quarterly basis.[219]

2. MISO TOs' Request for Rehearing of Opinion No. 551

105. MISO TOs sought rehearing of Opinion No. 551 on this issue.[220] MISO TOs argue that nothing in the record suggests that investors are more likely to rely on an earnings forecast if more analysts helped develop the forecast. Additionally, MISO TOs argue that *Value Line*'s growth projections have as much, if not more, influence on investment decision-making as the IBES estimates.[221] Furthermore, they assert that the IBES growth estimates lack transparency regarding the forecast and updating procedures, a defect "not common to *Value Line*'s estimates."[222] As an example of this opacity, MISO TOs point to Mr. Keyton's testimony which, they argue, concedes that there is no way to know how many analysts contribute to any IBES growth estimate.[223] In contrast, MISO TOs contend that Dr. Avera argued that *Value Line*'s short-term growth estimates meet the same objective criteria of IBES's, are widely relied upon by investors, and are based on transparent forecast techniques explained in *Value Line*'s user manual.[224]

106. MISO TOs further contend that the Commission relied on an erroneous assumption about the frequency of IBES updates, as Mr. Solomon stated that the IBES update frequency is indeterminable. Additionally, MISO TOs argue that Dr. Avera explained that *Value Line*'s projections "are updated on a scheduled basis, which removes debate about the potential staleness of the underlying data."[225] MISO TOs argue, therefore, that the record contradicts the Commission's findings about the update frequency of IBES and Value-Line. Nonetheless, MISO TOs argue that update frequency

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[219] *Id.*

[220] MISO TOs Rehearing Request at 5.

[221] *Id.* at 8.

[222] *Id.*

[223] *Id.*

[224] *Id.* at 8-9.

[225] *Id.* at 9.

is irrelevant in light of the fact that the investment community relies on *Value Line*.[226] To this point, they argue that "[w]hat matters is whether" growth estimates are representative of investor expectations, and that investors' "undisputed reliance" on *Value Line* establishes that such estimates are suitable for the DCF model.[227] MISO TOs also argue that the Commission has relied on *Value Line* investment data in other contexts.[228]

107. Furthermore, MISO TOs argue that the Commission erroneously assumed that investors are more likely to rely on a consensus forecast even though the record does not demonstrate that IBES estimates reflect a greater consensus of input than *Value Line* estimates. To this point, they argue that Mr. Keyton stated, and Mr. Solomon confirmed, that there is no way to ascertain the number of IBES analysts contributing to an estimate or if more than one analyst was responsible for any particular forecast.[229] MISO TOs therefore ask the Commission to grant rehearing and leave open the ability of parties to propose appropriate alternatives to IBES, including *Value Line*.[230] Additionally, MISO TOs argue that undisputed record evidence confirms that *Value Line* estimates are reviewed by a committee of peer analysts, which undercuts the worth of the Commission's determination that such estimates are only published under the name of a single analyst.[231] They also argue that, even if IBES provides updates with greater frequency, this is actually a disadvantage because such updates do not adhere to any known schedule or published metrics. In contrast, MISO TOs point out that *Value Line*'s earnings forecasts are updated quarterly in accordance with documented procedures.[232]

108. MISO TOs also argue that the Commission has not rejected the use of *Value Line* growth estimates in natural gas pipeline rate cases based on the fact that they are estimates of a single analyst and do not constitute consensus estimates.[233] They argue

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[226] *Id.* at 10.

[227] *Id.*

[228] *Id.* (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 102 and *Kern River Gas Transmission Co.*, Opinion No. 486-C, 129 FERC ¶ 61,240, at P 50 (2009)).

[229] *Id.* at 11.

[230] *Id.* at 12.

[231] *Id.*

[232] *Id.* at 13.

[233] *Id.* at 14.

that this finding in Opinion No. 551 contradicts the Commission's earlier finding in Opinion No. 531-B, where the Commission concluded that investors' reliance on IBES growth projections does not vary depending upon the "the exact number of analysts contributing to any particular IBES growth projection."[234]

109. Finally, MISO TOs argue that the Commission's categorical rejection of *Value Line* growth projections deprives the Commission of information relevant to the determination of a just and reasonable ROE.[235]

3. Second Complaint Proceeding

110. In the Second Complaint proceeding, the MISO TOs again proposed to use *Value Line* growth projections as the short-term projection of growth in future dividends. The Presiding Judge, however, rejected that proposal and determined that IBES data should be used.[236] The Presiding Judge held that, because the Commission had used IBES data as the short-term growth projection in Opinion No. 531, the MISO TOs had the burden to demonstrate that use of *Value Line* growth projections would be preferable in this case. The Presiding Judge was not persuaded by the MISO TOs' contention that the *Value Line* short-term growth projection should be used, because the resulting DCF midpoint and upper midpoints (9.50 and 10.89 percent) are closer to the result of the alternative methodologies than the DCF midpoint and upper midpoint produced using IBES growth projections (8.72 and 9.70 percent).[237] The Presiding Judge found that the alternative methodologies should not be referred to in deciding what short-term growth projection should be used in a DCF analysis. The Presiding Judge also found that use of the IBES short-term growth projections "better conforms to the Commission's admonition that the DCF model incorporate the most recent data available,"[238] because the IBES projections in the record were obtained as late as January 8, 2016, while the *Value Line* growth projections were obtained for various proxy group companies on October 30, November 30, and December 18, 2015.

111. In its brief on exceptions, MISO TOs argued, among other things, that prior reliance on IBES does not foreclose the use of *Value Line* growth projections, and it

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[234] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72.

[235] MISO TOs Rehearing Request at 18-19.

[236] Initial Decision (II), 155 FERC ¶ 63,030 at PP 32-45.

[237] *Id*. PP 36-41.

[238] Initial Decision (II), 155 FERC ¶ 63,030 at P 42.

again argued that the *Value Line* DCF is corroborated by the results of its risk premium, CAPM, and expected earnings analyses.[239] MISO TOs contend that a DCF analysis using *Value Line* short-term growth projections produces ROEs close to those produced by the alternative methodologies, such as a DCF analysis using IBES short-term growth projections. MISO TOs also argued that the *Value Line* estimates are at least as current as the IBES estimates. MISO TOs explained that, although the IBES growth projections in the record were in an IBES report published in January 2016, the analyst growth projections reflected in the report may have been made as much as 180 days earlier. MISO TOs cited evidence that *Yahoo Finance* provides no information as to the schedule or frequency of updates to any of the analyst growth projections used to create the consensus IBES growth projection published by *Yahoo Finance*.

112. In their briefs opposing exceptions, CAPs, OMS, RPGI, and Trial Staff all disagree with MISO TOs on this issue.[240] CAPs contend that *Value Line* growth projections are not similar to IBES short-term growth projections for at least three reasons. First, IBES short-term growth projections represent a consensus of the views of multiple analysts, while *Value Line* projections are made by only one analyst. Second, CAPs state that the *Value Line* growth rates are substantially retrospective in contrast to the prospective IBES growth projections. CAPs state that IBES analysts typically start from a single most recent historical year, make adjustments to that base year to remove non-recurring gains or losses, and then project normalized earnings growth over a three to five year period. However, *Value Line* growth rates represent an estimate of growth from a three-year historical period to a three-year forecast period, with the base period starting up to four years before the date of the *Value Line* publication.[241] Third, CAPs assert that the *Value Line* growth rates do not reflect as accurate a normalization of non-recurring base period gains and losses as the IBES projections. They state that the *Value Line* growth rates rely solely on an averaging of the three historical years, whereas IBES participating analysts make adjustments to the most recent year to remove specific non-recurring gains and losses.[242] OMS and Trial Staff also argue that the IBES growth projections are more current, because IBES updates its data base on a daily basis as participating analysts provide new inputs, whereas *Value Line* publishes on a rolling

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[239] MISO TOs Br. on Exceptions at 12-30.

[240] CAPs Br. Opposing Exceptions at 6-32; OMS-JCA Br. Opposing Exceptions at 9-16; RPGI Br. Opposing Exceptions at 4-29; Trial Staff Br. Opposing Exceptions at 6-13.

[241] CAPs Br. Opposing Exceptions at 12-13.

[242] *Id*. at 13.

quarterly basis.[243] Trial Staff and RPGI also oppose MISO TOs' reliance on alternative methodologies to support use of *Value Line* growth rates in the DCF model, asserting that alternative methodologies may only be considered after the DCF analysis has been completed.[244]

4. Briefing Order

113. In the Briefing Order, the Commission stated that, while IBES growth projections represented a consensus in the past, they may not reflect as robust a consensus at this point.[245] The Commission stated that this concern stems from the fact that most investment analysts that make and publish quarterly and annual earnings estimates no longer make and publish three-to-five year short-term projections of earnings growth and that in recent years, the IBES data for many proxy companies have reflected between one and three analysts' short-term growth projections.[246] The Commission further stated that the reduced number of short-term growth projections means that a significant change in a single analyst's growth projection for a particular proxy company can significantly affect that company's DCF analysis result.[247]

5. MISO TOs' Initial Briefs

114. In their brief in the First Complaint proceeding, MISO TOs state that they do not propose reliance on growth rates from a source other than IBES to resolve the First Complaint.[248] However, they ask the Commission to clarify that it is receptive to considering in the future other sources of growth rate estimates that are widely relied

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[243] OMS-JCA Br. Opposing Exceptions at 13-14; Trial Staff Br. Opposing Exceptions at 12.

[244] Trial Staff Br. Opposing Exceptions at 9-11; RPGI Br. Opposing Exceptions at 14.

[245] Briefing Order, 165 FERC ¶ 61,118 at P 48.

[246] *Id.* P 49 (citing *Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 47).

[247] *See e.g., id.* P 48 (noting, for example, that one analyst's error involving the growth projection for Portland General Electric Company (Portland General) reduced the overall Reuters consensus projected short-term percentage growth in earnings for Portland General from 10.96 percent to 7.80 percent).

[248] MISO TOs Initial Br. (I) at 22.

upon in the investment community, such as *Value Line*.[249] They argue that, from the earliest application of the two-step DCF, the Commission has neither adopted nor endorsed IBES as the only source of data for developing short-term growth projections.[250] They also state that the Commission has conceded that there is no perfect data source for such estimates and that the order directing briefing questions whether IBES growth rates reflect investor consensus.[251] For these reasons, they ask the Commission to clarify that it is open to considering sources of short-term earnings growth rate estimates other than IBES.[252]

115. In their brief in the Second Complaint proceeding, MISO TOs propose to use the *Value Line* growth estimates they presented at the hearing as the short-term estimate of the future growth in dividends.[253] MISO TOs rely on the same rationale as in their Brief on Exceptions to Initial Decision (II).

6. RPGI Initial Briefs

116. RPGI provides arguments in support of the use of IBES. RPGI contends that the Commission has previously considered and rejected concerns regarding the number of IBES analysts when using such data in the DCF model and the Commission has previously found that calculating the "common equity to a regulated enterprise depends upon what the market expects not upon precisely what is going to happen."[254] RPGI argues that the focus of the analysis in formulating a policy choice among financial models should not be whether the IBES growth estimates are the product of numerous inputs but whether there is "sufficient continuity and regularity over time in the publication of analysts' estimates that investors might reasonably make use of those

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[249] *Id.*

[250] *Id.* at 23 (citing *Ozark Gas Transmission Sys*., 68 FERC ¶ 61,032, at 61,106 (1994), *order on reh'g*, 71 FERC ¶ 61,138 (1995)).

[251] *Id.* (citing Opinion No. 414-B, 85 FERC at 62,269 (1998)).

[252] *Id.*

[253] MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 19-20.

[254] RPGI Initial Br. (I) at 22 (citing Opinion No. 414-B, 85 FERC at 62,268-69); RPGI Initial Br. (II) at 26 (citing same).

estimates in evaluating proxy companies' prospects."[255] It argues that there is no evidence to suggest that IBES inputs fail under this analysis.

117. RPGI also states that investors continue to make use of IBES forecasts and thus, the DCF continues to meet the Commission's established criterion for selecting which source to use—that the source is used by investors.[256] It also argues that it is not a defect that IBES forecasts "appear to be published on a basis that excludes estimates made more than six months prior."[257]

7. CAPs Reply Brief

118. CAPs' reply brief in the First Complaint proceeding did not address the issue of what short-term growth projection to use in the DCF model. However, in their reply brief in the Second Complaint proceeding, CAPs oppose use of *Value Line* as the short-term growth projection, repeating the same arguments they made in their brief opposing exceptions in the Second Complaint proceeding.

8. Trial Staff Reply Briefs

119. In reply to MISO TOs' Initial Briefs in both complaint proceedings, Trial Staff reiterates the Commission's arguments about its preference for IBES. It also points to Opinion No. 531-B, where the Commission stated that it is "preferable to use a consistent source of dividend growth projections for all members of the proxy group as provided by IBES, rather than to use different sources of growth projections depending upon the number of analysts contributing to each IBES growth projection."[258] Moreover, Trial Staff states that the Commission has a long history of finding that IBES is the preferred data source for computing the short-term growth rates[259] and that alternate sources should only be used when they are available for the growth projections for all proxy group companies in order to avoid skewed results.[260] Trial Staff also points out that the

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[255] RPGI Initial Br. (I) at 22; RPGI Initial Br. (II) at 26.

[256] RPGI Initial Br. (I) at 23; RPGI Initial Br. (II) at 27.

[257] RPGI Initial Br. (I) at 23; RPGI Initial Br. (II) at 27.

[258] Trial Staff Reply Br. (I) at 15-16 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72); Trial Staff Reply Br. (II) at 15.

[259] Trial Staff Reply Br. (I) at 16; Trial Staff Reply Br. (II) at 15.

[260] Trial Staff Reply Br. (I) at 17; Trial Staff Reply Br. (II) at 17.

Commission has found that IBES is updated on a rolling basis, sometimes as frequently as daily, while *Value Line*'s growth estimates are updated only on a lagging quarterly basis.[261] Trial Staff therefore recommends that the Commission reject the proposed use of *Value Line*-based short-term growth rates in the future and any alternative source that does not include all proxy group companies.[262]

9. Commission Determination

120. For the reasons discussed below, we deny MISO TOs' request for rehearing of Opinion No. 551's rejection of their request for clarification that *Value Line* growth projections constitute an acceptable source of short-term earnings growth estimates for use in the two-step DCF analysis. We also affirm the Presiding Judge's rejection of the MISO TOs' proposal in the Second Complaint proceeding to use *Value Line* growth projections as the short-term growth projection for purposes of the two-step DCF analysis and therefore we deny MISO TOs' exceptions on this point.

121. In Opinion No. 531, the Commission held that "in future public utility cases, the Commission will adopt the same two-step DCF methodology it uses in natural gas and oil pipeline cases."[263] Although the Commission has refrained from mandating the exclusive use of IBES data in its natural gas and oil pipeline rate of return cases, the Commission has in fact used IBES data for the short-term growth projection in every such case since the Commission initiated the two-step DCF model 25 years ago in *Ozark Gas Transmission System*.[264] For example, when the Commission increased the weighting of the short-term growth projection from one-half to two-thirds in Opinion Nos. 414-A and 414-B,[265] the Commission reaffirmed the use of IBES data for the short-term growth projection and rejected the use of *Value Line* short-term growth projections. Opinion No. 414-B cited testimony that "there is a body of evidence showing that the most reliable measure of investor expected growth is the growth forecasts, such as IBES,

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[261] Trial Staff Reply Br. (I) at 14-15; Trial Staff Reply Br. (II) at 14-15.

[262] Trial Staff Reply Br. (I) at 17-18; Trial Staff Reply Br. (II) at 17.

[263] Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

[264] *Ozark Gas Transmission Sys*., 68 FERC ¶ 61,032 at 61,106-07. *Nw. Pipeline Corp*., 79 FERC ¶ 61,309 at 62,384-85.

[265] *Transcon. Gas Pipe Line Corp*., Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,423-24 (1998), *reh'g denied*, Opinion No. 414-B, 85 FERC at 62,268-69.

published by security analysts."[266] That evidence included the article by Robert Harris, entitled *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*,[267] upon which the MISO TOs rely in this case to support their use of a one-step DCF method as part of their CAPM analysis. Opinion No. 414-B stated that article supported the use of IBES growth projections.[268] The Commission also quoted the testimony of the pipeline's witness that "[t]he analysts from which IBES collects forecasts are professionals, exercising their best judgment as to the future growth in earnings of the companies they follow . . . Their analyses are provided as a service to investors and should therefore serve as a good measure of the expectations investors have formed. I believe that IBES and Zacks Investment Research . . . are the best sources. IBES is well known in the investment community, and I believe draws on more professional forecasts than any other similar service except for Zacks."[269]

122. The Commission continued to follow this precedent in subsequent natural gas and oil pipeline rate of return cases.[270] The Commission also rejected proposals to average IBES short-term growth projections with *Value Line* growth estimates, finding that *Value Line* projections are "projections from a single source" and their use would "dilute the industry consensus reflected in the IBES data."[271]

123. Similarly, when the Commission modified its proxy group policies to permit MLPs to be included in natural gas and oil pipeline proxy groups, the Commission held that IBES growth projections should also be used for MLPs, finding that those

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[266] Opinion No. 414-B, 85 FERC at 62,269.

[267] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Fin. Mgmt., Spring 1986.

[268] Opinion No. 414-B, 85 FERC at 62,269 n.34.

[269] *Id.* at 62,269

[270] *See, e.g.*, *Nw. Pipeline Corp.*, 87 FERC at 62,058-59 (explaining that the "IBES data is a compilation of projected growth rates from various knowledgeable financial advisors within the investment community"); *Nw. Pipeline Corp.*, 92 FERC at 62,002; and *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 234 (2002).

[271] *Nw. Pipeline Corp.*, 87 FERC at 62,058-59; *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 234.

projections remain "the best and most reliable source of growth information available."[272] The Commission again found that investors rely on the IBES growth projections in making investment decisions, because they are widely available and generally reflect the input of a number of financial analysts. The Commission also rejected a proposal to use *Value Line* reports to test the reasonableness of IBES growth projections.[273]

124. MISO TOs have failed to provide a persuasive reason for the Commission to modify this longstanding policy concerning the short-term growth projection to be used in the two-step DCF model. For the reasons we discuss below, we continue to find the use of IBES three-to-five year growth projections preferable to the use of *Value Line* growth projections.

125. MISO TOs point out that, in Opinion No. 531, the Commission stated that the short-term growth projection to be used in the two-step DCF model "will be based on the five-year projections reported by IBES (or a comparable source)."[274] They contend that *Value Line* is a "comparable source," and thus Opinion No. 531 permitted its use. However, we find that *Value Line* is not a comparable source. As we have previously found, the IBES growth projections generally represent consensus growth estimates by a number of analysts.[275] By contrast, the *Value Line* growth estimates represent the growth projection of a single analyst, as Opinion No. 531-B stated.[276] MISO TOs assert that the *Value Line* growth estimates are comparable to consensus estimates, because they "are vetted through internal processes including review by a committee composed of peer analysts."[277] However, regardless of any review process within *Value Line,* the fact remains that the *Value Line* growth projections are projections by a single institution. By

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[272] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at P 75 (2008) (*Proxy Group Policy Statement*).

[273] *Id*. PP 83-84.

[274] MISO TOs Br. on Exceptions at 14 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 39).

[275] Ex. JCI-14 (II) at 27 ("IBES consensus estimates are normally based on the average of multiple analysts, or brokerage or investment firms' estimates.").

[276] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72 n.145 (stating that the *Value Line* data "for any company consists of an earnings estimate from only one analyst, rather than consensus estimates").

[277] MISO TOs Rehearing Request at 12 (citing Ex. S-1 at 17 and Ex. MTO-1 at 27).

contrast, IBES compiles the growth projections of a number of analysts at different brokerage and investment firms. The IBES growth projections thus generally represent an average of projections made independently of one another by a number of analysts at different institutions.[278] Data sources can reflect investor expectations by being used by large numbers of investors and/or being themselves the results of the analysis of a diverse group of persons in the investment community. Both IBES and *Value Line* growth rates are used by large numbers of investors but only IBES growth rates reflect the analysis of a diverse group of persons in the investment community.

126. Academic research supports the use of consensus forecasts such as those reported by IBES for purposes of the DCF growth projection, rather than the forecast of a single analyst or institution. For example, Roger Morin states,

> Exclusive reliance on a single analyst's growth forecast runs the risk of being unrepresentative of investors' consensus forecast. One would expect that averages of analysts' growth forecasts, such as those contained in IBES or Zacks, are more reliable estimates of investors' consensus expectations likely to be impounded in stock prices. Averages of analysts' growth forecasts rather than a single analyst's forecasts are more reliable estimates of investors' consensus expectations.[279]

The Harris article, *Required Rates of Return*, cited by Opinion No. 414-B, similarly supports the use of a survey of multiple analyst growth projections, such as IBES, for the DCF growth projection. In addition, Harris and Marston concluded in *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts* that use of IBES growth

[278] As MISO TOs point out, the Commission has recognized that in a few instances an IBES growth projection may be based on the projection of a single analyst. MISO TOs Rehearing Request at 16 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 71-72). However, the fact that a few of the IBES growth projections may not represent the consensus of more than one analyst or institution's growth projection does not justify shifting to a source of growth projections in which none of the growth projections reflect a consensus of more than one analyst or institution's growth projection. For the reasons discussed above, we believe it is appropriate to use as many consensus growth projections as possible, and participants are free to propose alternatives to IBES to the extent they may provide more robust consensus projections.

[279] Morin at 302.

projections offer "a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena."[280]

127. The record in these proceedings includes testimony to the same effect. For example, CAPs' witness, Mr. Gorman, stated, "Because IBES captures a greater number of analysts' growth rate projections, it more likely reflects the information used by investors to form investment decisions."[281] Similarly, Trial Staff's witness, Mr. Keyton, stated, "I believe that IBES growth estimates have a higher potential for representing a broader consensus in the investor community."[282] Thus, we believe it is appropriate to use IBES as the short-term growth projection, not simply because investors use IBES, but also because the consensus growth projection reported by IBES reflects the information which the analysts, brokerage and investments firms contributing to IBES provide to their clients.

128. We also find that the IBES growth projections are generally more timely than the *Value Line* projections. IBES updates its data base on a daily basis as participating analysts revise their forecasts,[283] whereas *Value Line* publishes its projections on a rolling quarterly basis.[284] Thus, the IBES consensus growth projection will immediately reflect any change a contributing analyst makes in its forecast. However, *Value Line* will not reflect such changes until its next quarterly report. MISO TOs suggest that some analyst projections reflected in the IBES consensus projections may be stale, whereas *Value Line*'s quarterly publication schedule guarantees that all analyst projections are updated on a quarterly basis. However, the record indicates that IBES has a policy of retaining each analyst's estimate in its data base for only 180 days.[285] Although some questions have been raised as to whether *Yahoo Finance* always follows this policy, in this case the evidence indicates that the IBES growth projections for the proxy companies are regularly updated. For example, the IBES growth projections of 26 of the 30 companies

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[280] Robert S. Harris & Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Fin. Mgmt., Summer 1992, at 6.

[281] Ex. ICG-15 at 10 (II).

[282] Ex. S-1 at 112 (II).

[283] As testified by Mr. Solomon, *Yahoo Finance*, which publishes IBES, "update[s] it daily as any of the growth rates that it accesses changes." Hearing Transcript (II) at 31.

[284] Ex. MTO -22 (II) at 79.

[285] Hearing Transcript (II) at 128.

that are in the proxy groups for both the First and Second Complaint proceedings changed in the course of the six months between the dates when the IBES projections were downloaded.[286]

129. MISO TOs also contend that the Commission has relied on *Value Line* growth forecasts in its public utility rate of return cases in the past.[287] However, in each of the cases cited by MISO TOs, *Value Line* data was used for the purpose of implementing the "br + sv" growth formula[288] which the Commission previously used as part of the one-step DCF model, but the Commission discontinued using that model in Opinion No. 531. The Commission used *Value Line* data, rather than IBES data, for the purpose of implementing the br + sv formula, because not all of the necessary data is published by IBES. In any event, the Commission also consistently used IBES growth projections as a second growth projection as part of its one-step DCF method.[289]

130. MISO TOs suggest that IBES growth projections could be overly optimistic, because analysts contributing to those projections may be selling the stocks that they are reporting on, whereas *Value Line* is an independent research firm not engaged in buying and selling stocks.[290] The Commission disagreed with this contention in Opinion No. 414-B, stating that analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients.[291] Investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies. Moreover, there is no evidence in these proceedings that analysts contributing to IBES

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[286] Compare the IBES growth projections in the MISO Initial Decision, 153 FERC ¶ 61,027, App. B to the IBES growth projections in Ex. MTO-34 (II) at 1.

[287] MISO TOs Br. on Exceptions at 14 (citing, e.g., *RiteLine Ill., LLC*, 137 FERC ¶ 61,039 (2011), *reh'g denied*, 149 FERC ¶ 61,238 (2014); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 (2011); *Bangor Hydro-Elec. Co*., 122 FERC ¶ 61,265 (2008); *So. Cal. Edison Co*., Opinion No. 445, 92 FERC ¶ 61,070, at 61,263 (2000).

[288] Under that formula, "b" is the expected retention formula, "r" is the expected earned rate of return on common equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

[289] *See, e.g*., *RiteLine Ill., LLC*, 137 FERC ¶ 61,039, at P 68; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46; *Pub. Serv. Elec. & Gas Co*., 126 FERC ¶ 61,219, at P 62 (2009); Opinion No. 445, 92 FERC at 61,265.

[290] MISO TOs Rehearing Request at 17 n. 44.

[291] Opinion No. 414-B, 85 FERC at 62,270.

provide more optimistic growth projections, than *Value Line* analysts. In fact, the *Value Line* growth rates tend to be higher than those of IBES. For instance, in the Second Complaint, where the MISO TOs seek to use *Value Line* instead of IBES data, use of the former instead of the later would increase the midpoint of their proposed DCF zone of reasonableness by 77 basis points from 8.73 percent to 9.50 percent.[292]

131. Finally, MISO TOs contend that the Presiding Judge in the Second Complaint proceeding erred in rejecting their contention that the *Value Line* short-term growth projection should be used, because the resulting DCF midpoint and upper midpoints (9.50 and 10.89 percent) are closer to the results of the alternative methodologies than the DCF midpoint and upper midpoint produced using IBES growth projections (8.72 and 9.70 percent).[293] The Commission denies this exception. In this order, we are deciding to use only the DCF and CAPM models to determine public utility ROEs. Therefore, the fact that using *Value Line* growth projections may produce results closer to the ROEs proposed by MISO TOs based on the Expected Earnings and Risk Premium models is irrelevant. More significantly, we find that the DCF and CAPM models should be implemented independently of one another. They are separate models based on different assumptions and inputs. We have no basis to find either model more reliable than the other. Therefore, there is no reason to decide issues concerning the implementation of either model based upon which resolution produces an ROE closest to the ROE produced by the other model.

132. The Commission has discretion in this proceeding to make a determination about available data sources in calculating the DCF. In making this determination, we agree with Trial Staff that it is preferable for the Commission to use a consistent source of dividend growth, such as IBES, for projections for all members of the proxy group.[294] Furthermore, we again note that the Commission has historically relied on IBES as the preferred source for computing short-term growth rates.[295]

133. MISO TOs also ask the Commission to leave open the ability of parties to propose appropriate alternatives to IBES, including *Value Line.* Parties are free to propose whatever data sources they deem appropriate. However, absent compelling reasons why, we will continue to rely exclusively on IBES as the preferred source for short-term growth projections for the purpose of performing the DCF analysis. Moreover, while this order lays out changes to the Commission's method for determining the ROE, wherever

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[292] Ex. MTO-34 (II).

[293] Initial Decision (II), 155 FERC ¶ 63,030 at P 39.

[294] Trial Staff Reply Br. at 15-16 (citing Ex. 531-B at P 72).

[295] Trial Staff Reply Br. at 16.

possible, we seek to provide predictability. Such predictability would be undermined if, in each proceeding, parties cherry pick whichever data best supports their desired results, leaving the Commission to adjudicate which is superior in each proceeding. Although MISO TOs have offered arguments to suggest that *Value Line* is a comparable source, the record in this proceeding still indicates that IBES is more stable and robust because IBES represents the views of multiple analysts and is updated more frequently.

D. Long-Term Growth Projection

134. As described above, the Commission's current policy is to require the DCF analysis of an individual company to include a projection of the long-term growth in dividends based on the growth in gross domestic product (GDP). The long-term growth projection is given one-third weight, with a short-term growth projection given two-thirds weight. For the reasons we discuss below, the Commission reaffirms this policy and will continue to require a long-term growth projection in the DCF analysis.

1. Opinion No. 551

135. During the hearing in the First Complaint proceeding, the MISO TOs, CAPs, and Trial Staff all presented DCF studies that included long-term growth projections based on growth in GDP, consistent with Commission policy. The Presiding Judge approved the 4.39 percent GDP growth projection included in Trial Staff's DCF study, reasoning that its method of calculating the growth rate most closely paralleled that which the Commission used in Opinion No. 531.[296] Thereafter, when the Initial Decision was considered by the Commission, no exceptions were raised by any party regarding the Presiding Judge's rulings concerning the long-term growth projection. The Commission approved the DCF study with a long-term growth projection in Opinion No. 551,[297] and no issue concerning the use of long-term growth projections in the DCF study was raised on rehearing of Opinion No. 551.

2. Second Complaint Proceeding

136. In the Second Complaint proceeding, the participants, including the MISO TOs, again all presented DCF studies that included long-term growth projections based on growth in GDP, and the Presiding Judge again adopted Trial Staff's long-term growth projection of 4.35 percent. No party filed an exception to the Presiding Judge's finding on this issue.

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[296] Initial Decision (I), 153 FERC ¶ 63,027 at PP 51-53.

[297] Opinion No. 551, 156 FERC ¶ 61,234 at P 65.

3. Initial Briefs

137. In their Initial Brief in response to the Briefing Order, MISO TOs assert that, when the Commission adopted the two-step DCF method for electric utilities in Opinion No. 531, the Commission concluded that the long-term growth rate portion of that method moderates the estimated cost of equity, rendering a high-end outlier test unnecessary.[298] MISO TOs accordingly oppose the high-end outlier test proposed in the Briefing Order. However, they state that, if the Commission nevertheless applies a high-end outlier test to the DCF model, then it should employ a single-stage, constant growth DCF, rather than a two-stage DCF, and eliminate the long-term growth projection.[299]

138. The MISO TOs contend that there are significant shortcomings in using GDP growth rates as part of the DCF analysis. MISO TOs' witness, Mr. McKenzie, comments that practical application of the DCF model requires a growth estimate that matches investors' expectations, which he asserts is less than the 30 year horizon for GDP growth estimates.

139. MISO TOs assert that there are no utility-specific, long-term growth projections available to the public. Therefore, although the DCF model is supposed to reflect investor behavior, it includes GDP growth estimates that investors do not use. As a result, this approach gives greater weight to the theory that all firms' growth rates converge to long-term GDP growth over actual investor behavior.[300]

140. MISO TOs assert that GDP growth estimates understate investors' expectations for electric utility growth and fall well short of analysts' estimates of the proxy companies' growth rates during the study periods in these proceedings.[301] Mr. McKenzie asserts that actual historical growth rates for certain individual proxy companies refute the notion that the long-term growth of electric utilities is constrained by GDP. For example, he states that *Value Line* reports included in the First Complaint proceeding record indicate that Alliant Energy and Eversource Energy had a 10-year earnings per share growth rate of 8 percent, while OGE Energy and IDACORP, Inc., had 10-year

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[298] MISO TOs Initial Br. (I) at 16 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 118).

[299] *Id.* at 20 (citing App. 2 McKenzie Aff. (I) at 50-51).

[300] *Id*. at 20-21 (citing App. 2 McKenzie Aff. (I) at 42-43).

[301] *Id*. at 21 (citing App. 2 McKenzie Aff. (I) at 47). MISO TOs Initial Br. (II) at 36 (citing App. 2 McKenzie Aff. (II) at 43-44).

earnings per share growth rates of 8.5 percent and 9.0 percent respectively.[302] Mr. McKenzie also states that *Value Line* reports in the Second Complaint proceeding record indicate that ALLETTE, Eversource Energy, OGE Energy, and IDACORP had 10-year earnings per share growth rates of 7.0 percent, 8.0 percent, 8.5 percent, and 9.0 percent, respectively.[303] MISO TOs explain that Myron Gordon, the founder of the DCF model, believed that it should use growth estimates that correspond to investor expectations, and he was dubious about incorporating long-term growth rates into the DCF model.[304]

141. Also, the MISO TOs state that, according to Mr. McKenzie, the instant case does not present the kind of circumstances that might support using a two-step DCF with long-term growth estimates.[305] Mr. McKenzie states that when the Commission adopted the two-step DCF model for natural gas pipelines, the IBES short-term growth projections for those pipelines were substantially higher than the projected growth in GDP. For example, in *Transcontinental Gas Pipe Line Corp*., the IBES growth rates for the proxy group ranged from 8.0 percent to 15.0 percent and averaged 11.3 percent.[306] However, in the First Complaint proceeding, the IBES growth projections of all but one of the proxy companies are less than 8.0 percent,[307] and in the Second Complaint proceeding the IBES growth projections of all but two of the proxy companies are less than 8.0 percent.[308] Therefore, Mr. McKenzie asserts that there is no evidence in these proceedings that analysts' short-term earnings per share growth projections for electric utilities are characterized by the short-term optimism that led the Commission to adopt the two-step DCF model for natural gas pipelines. Mr. McKenzie also states that evidence presented by CAPs that electric utilities have entered a cycle of significant capital spending on

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[302] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 47.

[303] MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 43-44.

[304] MISO TOs Initial Br. (I) at 21; *id.*, App. 2 McKenzie Aff. (I) at 49 (citing Myron J. Gordon, The Cost of Capital to a Public Utility, 100-01 (MSU Pub. Util. Studies 1974)).

[305] *Id*. at 21 (citing App. 2 McKenzie Aff. (I) at 48-51).

[306] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 50 (citing Opinion No. 414-A, 84 FERC ¶ 61,084 at App. A).

[307] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 51 n.111.

[308] MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 48 n.97.

utility infrastructure suggests that GDP growth estimates understate investors' growth expectations for electric utilities.[309]

4. Reply Briefs

142. In their Reply Briefs, CAPs, Trial Staff and RPGI addressed issues raised by the MISO TOs. These three parties oppose MISO TOs' proposal to use a single-stage, constant growth DCF, rather than the two-step DCF method if the Commission applies a screen for high-end outliers.[310] RPGI asserts that over time the Commission has adopted and expanded its preference for the two-step DCF method, including support for the theoretical assumptions of the DCF formula requiring the use of a two-stage growth component.[311] CAPs argue that it is important to use an accurate representation of long-term dividend stream that investors expect, regardless of the tests used to filter outliers. CAPs also argue that, because MISO TOs are not proposing to filter out any DCF high-end results from the study-period analysis in this proceeding, they are essentially conceding that in this case the DCF model should apply a two-step composite growth rate.[312]

143. Moreover, in response to MISO TOs' assertion that the DCF model requires a growth estimate that matches investors' expectations, CAPs assert that this is a reason to use the long-term GDP constraints on analysts' projected rate of near-term growth in earnings per share. CAPs state that rational investors know what Dr. Roger Morin explains in his textbook: that utility holding companies seek to keep dividend growth on a path they can sustain over the long term to avoid having to cut dividends when earnings are down.[313] CAPs comment that the Commission recognized the importance of factoring in long-term growth even before Opinion No. 531,[314] but now MISO TOs are

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[309] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 47-48, 51.

[310] *See* CAPs Reply Br. (I) at 9; Trial Staff Reply Br. (I) at 18-19; RPGI Reply Br. (I) at 20-21.

[311] RPGI Reply Br. (I) at 21 (citing *Ozark Gas Transmission Sys*., 68 FERC at 61,105-07; *Wyoming Interstate Co*., 69 FERC ¶ 61,259 (1994); *Nw. Pipeline Corp*., 71 FERC ¶ 61,253, at 61,992 (1995)).

[312] CAPs Reply Br. (I) at 9.

[313] CAPs Reply Br. (I) at 10 (citing Morin at 284).

[314] Opinion No. 531, 147 FERC ¶ 61,234; Opinion No. 531-A, 149 FERC ¶ 61,032; Opinion No. 531-B, 150 FERC ¶ 61,165.

proposing to eliminate consideration of whether the growth projected by analysts for the next three-to-five years is sustainable over the long term. Further, CAPs argue that, consistent with its findings in Opinion No. 531, the Commission factored in a long-term growth projection in Opinion No. 551, and MISO TOs' did not seek rehearing.[315]

144. CAPs comment that Mr. McKenzie does not provide evidence to support his claim that investors do not rely on estimates of GDP growth in evaluating growth expectations for utility stocks.[316] CAPs state that Warren Buffet, who they say may be both the largest and most followed individual investor in U.S. electric utilities, has made clear that he expects stocks' long term earnings growth to be constrained by GDP growth.[317]

145. Further, CAPs dispute MISO TOs' reliance on the fact that in the First Complaint proceeding four of the proxy companies had 10-year earnings per share growth rates averaging 8.4 percent and in the Second Complaint proceeding four proxy companies had 10-year earnings per share growth rates averaging 8.1 percent. CAPs argue that, because the DCF model "turns" on investors' expected stream of dividend receipts, the growth in dividends over the last 10 years is more meaningful than growth in earnings per share. CAPS assert that in the First and Second Complaint proceedings the growth in dividends for the four proxy companies in question averaged less than 3.9 percent and 4.9 percent respectively.[318] Also, CAPs contend that Mr. McKenzie's focus on four proxy companies was cherry-picking. CAPs point out that in the First and Second Complaint proceedings, just looking at the top of the alphabet, one could equally point to the low 10-year earnings per share growth rates of American Electric Power (1.5 percent), Ameren (-2.0 percent), CenterPoint Energy (2.0 percent), and Consolidated Edison (3.5 percent).[319]

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[315] *See* CAPs Reply Br. (I) at 11.

[316] *Id.*

[317] *Id.* (citing Fortune, "Mr. Buffet on the Stock Market," Fortune, November 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/ ("You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems.").

[318] *Id.* at 12; CAPs Reply Br. (II) at 27.

[319] CAPs Reply Br. (I) at 12 (citing Ex. JC-10 at 44, 45, 48, 50). CAPs Reply Br. (II) at 27-28 (citing Ex. JCI-9 at 60, 61, 63 & 65).

146. MISO TOs argue that capital expenditures forecast in 2018 for 2018 imply higher long-term growth. In response, CAPs assert that the Commission should not accept Mr. McKenzie's view that capital investment can generate profit expansions that will long exceed GDP growth.[320] CAPs first argue that the relevance of this report in ascertaining the cost of equity during the study periods in these proceedings is not clear, because the April 2018 Regulatory Research Associates report uses data that post-dates both study periods. In any event, CAPs state that the referenced report indicates that capital expenditures of the covered electric industry holding companies will shrink from 2018 to 2020 to a level below that of 2016. CAPs also state that the Commission's composite-growth method giving two-thirds weight to the IBES short-term growth projection already assumes that near-term growth will continue for decades. Further, CAPs assert that the real focus of the DCF model is the expected rate of growth in dividends per share and that the near-term growth rate is better projected by factoring in long-term GDP growth, because electric utilities seek to keep dividend growth on a path they can sustain over the long run. CAPs argue that the resulting moderation of earnings growth in realized dividend growth can be seen by comparing past earnings per share (EPS) growth projections to actual dividend per share growth.[321]

147. CAPs dispute MISO TOs' reliance upon a 1974 publication expressing skepticism about the use of the two-stage DCF model. They argue that in the intervening decades the DCF model has been widely adopted and refined. They cite to Dr. Morin, author of a text cited by the Commission in the Briefing Order, as supporting "[a] multiple-stage DCF model that better mirrors the patterns of future dividend growth," and recognizing that "[a] transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate."[322]

148. CAPs disagree with MISO TOs' argument that the two-stage DCF was appropriate in the 1990s when electric utilities were transitioning to non-regulated markets, but that expectations of widespread deregulation no longer exist. CAPs explain that in fact the

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[320] MISO TOs Reply Br. (I) at 12-13 (citing *S&P Global Market Intelligence, RRA Financial Focus – Utility Capital Expenditures Update,* Regulatory Research Associates (Apr. 20, 2018)).

[321] CAPs Reply Br. (I) at 12-14. CAPs witness, Mr. Gorman, provides a comparison of the 2015 projections of three-to-five year EPS growth that are the basis for the composite growth rate used in Opinion No. 551 to the DPS growth rate between then and now. These companies' projected EPS growth rate averaged 5.15 percent, whereas their realized DPS growth rate averaged 3.83 percent. CAP witness Gorman Ex. JC-109 at 1.

[322] CAPs Reply Br. (I) at 14 (quoting Morin at 309).

Commission used a one-stage DCF model for electric utilities during the transitional period,[323] but that in Opinion No. 531, the Commission determined that it was no longer appropriate to consider the transitional period of deregulation as the basis for assuming utility stocks' near-term growth rates would continue indefinitely.[324]

149. CAPs argue that MISO TOs mischaracterize the testimony of Dr. J. Randall Woolridge before the Virginia State Commission as supporting the constant growth DCF model for DCF valuation procedures. CAPs argue that, in fact, Dr. Woodridge opposed basing DCF growth rate solely on analysts' projections of the near-term EPS growth.[325]

150. Trial Staff comments that their expert witness, Mr. Keyton, disagrees with McKenzie's elimination of the long-term growth component in the DCF. Trial Staff cites to the Commission's determination in *Williston Basin Interstate Pipeline Company* and Opinion No. 531 rejecting the one-step or constant growth DCF model in favor of a two-step DCF model.[326] Trial Staff also relies upon Dr. Morin who supports incorporating a long-term growth estimate in the DCF model and who was the Commission's authority for the conclusion that "all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy."[327] Mr. Keyton also notes that Professors Brigham and Ehrhardt support the use of longer term growth rates.[328]

5. Commission Determination

151. We disagree with MISO TOs' contention that the Commission should eliminate the long-term growth projection based on GDP from its DCF analysis of electric utilities. As the Commission held in Opinion No. 531,

> The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate

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[323] *Id.* at 15 (citing Opinion No. 445, 92 FERC at 61,266).

[324] *Id.* (citing Ex. JC-108 at 24).

[325] *Id.* at 16-17. (CAPs question the relevance of this testimony in an unrelated proceeding. *Id*.)

[326] Trial Staff Reply Br. (I) at 18.

[327] *Id.* at 19 (quoting Opinion No. 531, 147 FERC ¶ 61,234 at P 36 n.63).

[328] *Id.*

> commensurate with the investment's risk.[329] Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that 'projections by investment advisory services of growth for relatively short periods of years into the future' cannot be relied on 'without further consideration.' Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.[330]

152. MISO TOs have not provided a persuasive basis for us to depart from this policy. Although MISO TOs cite a 1974 article by Myron Gordon arguing that analysts' short-term growth projections may be used without reference to a longer-term projection, more recent academic works support inclusion of a long-term growth projection based on GDP. For example, in *New Regulatory Finance*, Roger Morin recognizes that there is a growing consensus that security analysts' growth projections are "the best place to start" in projecting growth in dividends. However, he continues,

> The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate . . . It is useful to remember that eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy.[331]

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[329] As the Commission explained, "The DCF model assumes growth for an infinite period of time. This can be approximated as 50 years because the present value of a one dollar dividend received 50 years in the future, discounted at 12 percent, is less than one cent." *Ozark Gas Transmission Sys.*, 68 FERC at 61,105 n.32 (citing Eugene F. Brigham & Louis C. Gapenski, Financial Management 291 (1991)).

[330] Opinion No. 531, 147 FERC ¶ 61,234 at P 33 (quoting *Consol. Gas Supply Corp.*, 24 FERC ¶ 61,046, at 61,105 (1983)) (footnotes omitted).

[331] Morin at 308.

Dr. Morin goes on to state that one way to account for the two stages of growth is to adopt a blended growth rate as the Commission does, giving two-thirds weight to analysts' five-year growth projections and one-third weight to long-range projections of growth in GDP projected for the very long-term.[332]

153. MISO TOs argue that, regardless of the fact that the underlying theory of the DCF model requires a long-term growth projection, as a practical matter investors rely solely on short-term growth projections, such as the IBES three-to-five year growth projections. MISO TOs assert that there are no long-term projections of the growth of public utilities and therefore investors must be limited to using short-term growth projections. However, MISO TOs fail to counter evidence that sophisticated investors do in fact consider long-term economic trends, including long-term growth in GDP, when estimating the future growth in earnings or dividends. For example, CAPs note that Warren Buffet has made clear that he expects firms' long-term earnings growth to be limited by GDP growth, stating,

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems.[333]

154. MISO TOs nevertheless assert that GDP does not constrain the growth in earnings of electric utilities, stating that the record in the First Complaint proceeding contains *Value Line* reports showing that four electric utilities had earnings per share growth rates over the previous 10 years of 8 to 10 percent, and the record in the Second Complaint proceeding contains similar *Value Line* reports showing that four electric utilities had earnings per growth rates of 7 to 9 percent. MISO TOs point to the proxy group companies featuring the highest growth rates, while the growth rates of the overall proxy group contradict their position. The First Complaint proceeding record includes *Value*

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[332] *Id*. at 309. In *Corporate Finance, A Focused Approach*, at 279 (Fourth Edition), Ehrhardt and Brigham also state "dividend growth for most mature firms is generally expected to continue in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)," and they also discuss a blended approach for determining the growth projection for the constant growth DCF model when the short-term growth projection is unsustainable. *Id*. at 324.

[333] "Mr. Buffet on the Stock Market," *Fortune*, November 22, 1999.

Line reports showing the average 10-year earnings growth rates for 41 electric utilities.[334] The median 10-year earnings growth rate for all 41 electric utilities was 3.5 percent, which is less than the long-term projected nominal GDP growth rate of 4.39 percent in that proceeding. Similarly, the Second Complaint proceeding record includes *Value Line* reports showing the average 10-year earnings growth rates for 30 electric utilities.[335] The median 10-year earnings growth rate for all 30 of those electric utilities is also 3.5 percent, which is less than the long-term projected nominal GDP growth rate of 4.35 percent in that proceeding. Thus, a review of all the *Value Line* reports in the exhibits cited by the MISO TOs indicates 10-year earnings growth more in line with the growth of the economy as whole.

155. In any event, the fact some electric utilities may maintain earnings growth in excess of GDP for periods of 10 years or more is not inconsistent with the Commission's two-step DCF model. As the Commission has previously explained, our two-step DCF model does not assume that an electric utility's growth rate will immediately drop to the GDP growth rate following the fifth year of the IBES short-term growth projection. "Our decision to give the IBES data two-thirds weight and the long-term projection one-third weight is the equivalent, in a 50-year model, of averaging 33 years at the higher IBES number and 17 years at the lower GDP number."[336] Therefore, the fact some electric utilities may have earnings growth in excess of the growth in GDP for periods of 10 years or more is not inconsistent with our holding that GDP is appropriate as a long-term growth rate given one-third weight.

156. MISO TOs also argue investors may expect public utilities to have earnings and dividend growth in excess of GDP, pointing to several reports that public utility capital expenditures are expected to increase. For example, MISO TOs cite a 2014 S&P report, stating among other things, "[b]eginning in 2017, we expect the industry's generation and overall capital spending needs to pick up significantly, consistently exceeding $100 billion annually."[337] In addition, they cite a 2018 report stating, "[f]orecasted 2018 capital expenditures for the 52 electric and gas utilities in the RRA universe climbed to

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[334] Ex. JCI-109 (I) at 42-86.

[335] Ex. JCI-109 (II) at 58-90.

[336] *Williston Basin Interstate Pipeline Co*., 87 FERC ¶ 61,264 at 62,004 (1999). *See also Williston Basin Interstate Pipeline Co*., 84 FERC ¶ 61,081 at 61,384-85 (1998).

[337] Standard & Poor's Corporation, *The Outlook for U.S. Regulated Utilities Remains Stable on Increasing Capital Spending and Robust Financial Performance*, RatingsDirect (Dec. 16, 2014) (2014 S&P Report).

an all-time high of $141.1 billion."[338] MISO TOs' reliance on these reports is unavailing. These reports relate to the public utilities' capital spending in the relatively near future, within a time frame during which, as discussed in the preceding paragraph, the two-step DCF model assumes growth consistent with the IBES growth projection. Therefore, these reports do not undercut the underlying rationale of the two-step DCF model that firms cannot grow faster than GDP over the indefinite long-term. Moreover, the 2018 S&P report was issued over two years after the financial study periods in the two complaint proceedings, the second of which ended on December 31, 2015, and therefore that report could not affect investor expectations during the time periods at issue in these proceedings. In any event, as CAPs point out, the 2018 S&P report indicates that capital expenditures of the covered electric industry holdings companies will shrink from 2018 to 2020 to a level below that of 2016.[339]

157. MISO TOs also seek to distinguish electric utilities from natural gas pipelines with respect to the need for a long-term growth projection. They argue that the IBES short-term growth projections of electric utilities are generally lower than natural gas pipeline IBES growth projections in the cases where the Commission first adopted the two-step DCF model. Opinion No. 531 recognized that the IBES growth projections of electric utilities reflect a different pattern from those of natural gas and oil pipelines. Although pipeline IBES growth projections are consistently higher than the long-term growth of GDP, that is not true of electric utilities.[340] Nevertheless, Opinion No. 531 adopted the two-step DCF model for electric utilities. The Commission pointed out that it had held that giving some effect to the long-term growth projection will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy.[341] Opinion No. 531 concluded that this reasoning applied

> regardless of whether the short-term growth projection is greater or less than the growth of the economy as a whole.

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[338] S&P Global Market Intelligence, *RRA Financial Focus – Utility Capital Expenditures Update*, Regulatory Research Associations (Apr. 20, 2018) (2018 S&P Report).

[339] See 2018 S&P Report, Table 1 ("Total Electric" Cap Ex of $93.6 million in 2016A, $106.6 million in 2018E, and $86.2 million in 2020E, its most distant prediction.).

[340] Opinion No. 531, 147 FERC ¶ 61,234 at P 30 (citing *S. Cal. Edison Co.*, 92 FERC at 61,261).

[341] Opinion No. 531, 147 FERC ¶ 61,234 at P 38 (citing Opinion No. 414-A, 84 FERC at 61,423).

> Over the long-run, a regulated firm may reasonably be expected to grow at the rate of the average firm in the economy; growth either significantly above or below the growth of the economy as a whole is unlikely to continue indefinitely. Using the same long-term growth projection for all public utilities is consistent with this expectation.[342]

158. In any event, regardless of the fact that the IBES growth projections of a number of public utilities are less than or about equal to projected growth in GDP, the IBES growth projections of the public utility proxy companies that set the top of the DCF zone of reasonableness in both proceedings are substantially above projected growth in GDP. In the First Complaint proceeding, TECO Energy (TECO) sets the top of the zone of reasonableness. The IBES short-term growth projection for TECO is 7.68 percent, 329 basis points above the long-term GDP growth projection of 4.39 percent.[343] In the Second Complaint proceeding, PNM Resources, Inc. (PNM) sets the top of the zone of reasonableness. The IBES short-term growth projection for PNM is 9.30 percent, over twice the long-term GDP growth projection in that case of 4.35 percent.[344] Thus, these public utilities present the same circumstances as the pipelines in the cases where the Commission adopted the two-step DCF method – IBES short-term growth projections substantially in excess of GDP growth. Because we determine the central tendency of the zone of reasonableness using the midpoint, it is particularly important that the ROEs of the companies setting the top of the zone be determined consistent with the underlying theory of the DCF model, requiring use of a long-term growth projection.

159. Finally, MISO TOs assert that, if the Commission applies a high-end outlier test to the DCF model, there will remain no rationale for requiring the long-term growth component of the two-step DCF model. The existence of the high-end outlier test is irrelevant to the question of whether a long-term growth projection should be included in a DCF analysis of public utilities. The high-end outlier tests eliminates outlier proxy group members. It does not address the fact that, over the long-term, companies cannot maintain their short-term growth rates and must, to some extent, converge on the growth rate of the overall economy. Furthermore, the high-end outlier test we adopt later in this order does not screen out any of the ROEs produced by the DCF analysis of the proxy groups in these two cases, including the ROE results discussed above that establish the top of the zones of reasonableness in these two cases.

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[342] *Id*.

[343] Initial Decision (I), 153 FERC ¶ 63,027 at App. B.

[344] CAPs Initial Br. (II) at App. I.

E. Has DCF Performed Inconsistently with Underlying Theory

160. In both Opinion Nos. 531 and 551, the Commission found that, because of unusual capital market conditions, the Commission had "less confidence" that the midpoint of the zone of reasonableness determined by the DCF analysis satisfied the *Hope* and *Bluefield* capital attraction standards.[345] For example, in Opinion No. 551, the Commission stated that bond yields remained at historically low levels during the January to June 2015 study period in the First Complaint proceeding. The yield on 10-year U.S. Treasury bonds, which the Commission noted in Opinion No. 531[346] was below two percent in that case and had not been below three percent since the 1950s, was at 2.07 percent during the Opinion No. 551 study period.[347] Also, the yield on short-term U.S. Treasury bonds was historically low, ranging from zero to 0.25 percent.[348]

161. Opinion No. 551 then considered the alternative cost of equity models to corroborate the Commission's determination to set MISO TOs' ROE "at a point above the midpoint" of the DCF analysis' zone of reasonableness, i.e., the midpoint of the upper half of the zone.[349] However, the Commission emphasized that it was not departing from the use of the DCF methodology to determine the zone of reasonableness.[350] At the hearings on the Second Complaint, the participants devoted a substantial portion of their evidentiary presentations to debating whether the continuing low-interest rate capital market conditions should be considered "anomalous" and whether those conditions distort the results of a DCF analysis.[351]

162. In the Briefing Order, the Commission stated that those issues are largely irrelevant under the Briefing Order's proposed approach to determining just and

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[345] Opinion No. 531, 147 FERC ¶ 61,234 at P 145; Opinion No. 551, 156 FERC ¶ 61,234 at P 119.

[346] Opinion No. 531, 147 FERC ¶ 61,234 at P 145 n.285.

[347] Opinion No. 551, 156 FERC ¶ 61,234 at P 121.

[348] *Id*.

[349] *Id.* P 135.

[350] *Id*. P 137.

[351] *See, e.g.*, Exs. JCA-1 at 6-18, JCI-1 at 29-32, 38, ICG-15 at 18-30, MTO-1 at 21-28, 102-105, MTO-16 at 16-38.

reasonable ROEs.[352] The Commission stated that, under this approach, it would average the cost of equity results produced by the DCF model with the results produced by the other proposed models, using the midpoint/medians of the models that produce zones of reasonableness, to get one average figure for the cost of equity. Therefore, the Commission would not be making an adjustment above the midpoint/median as it did in Opinion No. 551. The Commission stated that, as a result, there was no need to find that low-interest rate capital market conditions distort the results of a DCF analysis so as to justify adjusting the ROE for average risk utilities above the midpoint. To the contrary, the Commission's primary reason for proposing to average the results of the DCF analysis with the results of other models is that investors use those models, in addition to the DCF methodology, to inform their investment decisions. The Commission concluded that, under this approach, whether a change in the capital market conditions is anomalous or persistent is of less importance, because relying on multiple financial models makes it more likely that the Commission's decision would accurately reflect how investors are making their investment decisions.

163. Nevertheless, the Commission noted that, in recent years, utility stock prices appear to have performed in a manner inconsistent with the theory underlying the DCF methodology.[353] The Commission stated that, under that theory, increases in a company's actual earnings or projected growth in earnings would ordinarily be required to justify an increase in the company's stock price. However, the Commission stated that, although the Dow Jones Utility Average increased by almost 70 percent from October 1, 2012 through December 1, 2017, there was not an increase in either utility earnings or projected earnings during that period that would justify the substantial increase in stock prices. The Commission stated that this is an example of what MISO TOs have described as "model risk" —the risk that in some circumstances a model will produce results that do not reflect real world experience.[354] The Commission stated that

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[352] Briefing Order, 165 FERC ¶ 61,118 at P 46.

[353] *Id*. P 47.

[354] *Id*. (citing Ex. MTO-16 (II) at 36) ("There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled. Although the concept of model risk was originally applied to derivative instruments and hedging transactions, it applies equally to models used to value companies, to manage investment portfolios, to assign credit ratings, or in this case, to determine the ROE that will provide a fair return and encourage investment in critical infrastructure.").

it appears that, for whatever the reason, investors have seen greater value in utility stocks than the DCF methodology would predict. The Commission concluded that this suggests that the ROE estimated by that methodology may be correspondingly inaccurate.

1. CAPs

164. CAPs contest the Briefing Order's suggestion that current capital market conditions, including low bond yields, have affected the reliability of the DCF Model.[355] They contend that the Commission failed to support its assertion that utility stock prices appear to have performed in a manner inconsistent with the theory underlying the DCF model. In particular, they state that the Commission's statement that the DCF model assumes that stock prices increase only when there is an actual or projected increase in earnings/dividends is inaccurate. Rather, their witness, Mr. Bertram, explained that "[t]he theory underlying the DCF method is that stock prices can change not only as a result of expected changes in earnings/dividends ("g"), but also due to changes in investors' required rate of return for investing in a company ("k")."[356] Mr. Solomon states that factors influencing the investor's required rate of return include

> expected returns that might be earned on alternative investments, changes in risk perceptions, changes in risk tolerance, changes in a desire for current income versus longer-term capital gains, expectations about inflation, expectations about real interest rates, expectations about the U.S. economy in general and various sectors of the U.S. economy specifically as well as expectations about the global economy, among others.[357]

165. CAPs also point out that, in Order No. 489, the Commission explained that the DCF model does not assume that stock prices are solely a function of current and projected future earnings, stating the DCF model "shows the relationship between stock prices and dividends, growth rate of dividends, and shareholders' required rate of return."[358] Opinion No. 489 stated that the term "k" in the DCF model, representing

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[355] CAPs Initial Br. (I) at 18-21.

[356] Ex. JCI-100 at 22.

[357] *Id*. at 22-23.

[358] CAPs Initial Br. (I) at 20 (quoting *Generic Determination of Rate or Return on Common Equity for Public Utilities*, Order No. 489, FERC Stats. & Regs. ¶ 30,795 at 30,990 (1988) (cross-referenced at 42 FERC ¶ 61,122)). Ex. JCI-100 at 22-25.

shareholders' required rate of return, reflects a number of factors influencing stock prices, "including expectations about the real interest rates, the expected rate of inflation, and the 'risks' associated with owning a particular stock."[359]

166. CAPs assert that the increase in utility stock prices from 2012 to 2017 likely reflected the historically low interest rates the Commission noted in the Briefing Order, as opposed to "model risk." They contend that this conclusion is consistent with the Commission's own statement, quoted by the D.C. Circuit in *Tennessee v. FERC*, that a "drastic drop in interest rates attract[s] capital away from bonds and into stocks, causing a rise in stock prices and a decline in dividend yields."[360]

2. MISO TOs

167. MISO TOs contend that the Briefing Order properly determined that the limitations of the DCF model justify taking a broader perspective to the examination of ROE.[361] For example, they state that the Briefing Order documented that utility stock prices have trended in a manner inconsistent with the basic theory of the DCF model.

168. MISO TOs' witness, Mr. McKenzie, states that the Briefing Order's observation that utility stock prices rose by almost 70 percent without a corresponding increase in utility earnings during the period 2012 to 2017 is not critical to supporting the Commission's proposal to use multiple financial models to determine ROE. However, Mr. McKenzie states that the Briefing Order's observation illustrates that the behavior of investors in the financial markets can depart significantly from the underlying assumptions of the DCF model.[362] He states that the DCF model assumes dividends, earnings, and stock price growth at the same constant rate to infinity, resulting in a constant price/earnings ratio. Mr. McKenzie states that the Briefing Order's observation that utility stocks increased without a corresponding increase in earnings simply indicates that the price/earnings ratio was not constant, contrary to the DCF model's assumptions. He argues that real-world experience contradicts the DCF assumptions, which he claims illustrates that there is no perfect way to estimate the cost of equity and therefore reliance on multiple modes is fully supported.

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[359] *Id*. at 20 (quoting Order No. 489, FERC Stats. & Regs. ¶ 30,795 at 30,990).

[360] 926 F.2d 1206, 1209 (D.C. Cir. 1991) (quoting *Tenn. Gas Pipeline Co.*, 46 FERC ¶ 61,089, at 61,383 (1989)).

[361] MISO TOs Reply Br. (I) at 13-15.

[362] *Id.*, App. 2 McKenzie Reply Aff. (I) at 17-18.

3. Other Parties

169. RPGI contends that the Briefing Order failed to support its assertion that the increase in utility stock prices from 2012 to 2017 was not accompanied by a commensurate growth in earnings per share.[363] RPGI states that, in support of this assertion, the Briefing Order cited the *Coakley* Briefing Order,[364] and that order in turn cited only a single exhibit from the fourth complaint proceeding concerning the New England TOs' ROE.[365] RPGI states that the cited exhibit only contains information concerning utility stock prices and contains no information concerning earnings or projected earnings of any utilities.[366] RPGI also states that the period 2012 to 2017 extends beyond the 2015 test periods in the two MISO complaint proceedings and after the close of the records in these proceedings.

4. Commission Determination

170. As the Commission stated in the Briefing Order, the issue of whether the low-interest rate capital market conditions during 2015 were "anomalous" or may have distorted the results of the DCF model are not relevant to our revised approach to determining just and reasonable ROEs. In Opinion Nos. 531 and 551, the Commission relied on its finding of anomalous capital market conditions to justify setting the New England TOs' and MISO TOs' ROEs at the midpoint of the upper half of the DCF zone of reasonableness, despite the fact that the transmission owners are of average risk and the Commission ordinarily sets the ROE of average risk utilities at the central tendency of the overall zone of reasonableness. Under our revised approach to determining just and reasonable ROEs, we are averaging the results of the DCF and CAPM models to determine a composite zone of reasonableness and setting the ROE of average risk utilities at the central tendency of that composite zone of reasonableness. We are not making an adjustment above the central tendency of the zone of reasonableness as we did in Opinion Nos. 531 and 551. There is thus no need to find that low-interest rate capital market conditions distort the results of a DCF analysis so as to justify increasing the ROE for average risk utilities above the central tendency, and we make no such finding in this order.

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[363] RPGI Initial Br. (I) at 18-20; RPGI Initial Br. (II) at 20-22.

[364] Briefing Order, 165 FERC ¶ 61,118 at P 47 (citing *Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 45).

[365] RPGI Initial Br. (I) at 19 (citing Ex. CAP-65 in Docket No. EL16-64-002); RPGI Initial Br. (II) at 22 (citing same).

[366] RPGI Initial Br. (I) at 19; RPGI Initial Br. (II) at 22.

171. Rather, our revised ROE policy rests on a finding that investors use the DCF and CAPM models to inform their investment decisions. Under this approach, whether a change in capital market conditions is anomalous or persistent is of little importance, because relying on multiple financial models makes it more likely that our decision will accurately reflect how investors are making their investment decisions. Moreover, to the extent that investors in fact rely on a financial model, the fact that that model may have defects does not invalidate its use in determining ROE. A key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, i.e., induce investors to invest in the utility in light of its risk profile. For this purpose, we must look to the methods investors actually use to analyze and compare their investment opportunities, regardless of any flaws in those methods. As the Commission stated in Opinion No. 414-B, "the cost of common equity to a regulated enterprise depends upon what the market expects not upon precisely what is actually going to happen."[367] As we discuss elsewhere in this order, there is no serious dispute that investors use the DCF and CAPM models in making investment decisions. In any event, the application of the CAPM model mitigates some of the model risk that the DCF model may perform poorly in certain circumstances.

VI. Expected Earnings Model

A. Background

172. A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. The analysis can be either backward looking using the company's historical earnings on book value, as reflected on the company's accounting statements, or forward-looking using estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company.[368] The latter approach is often referred to as an "Expected Earnings analysis." The Expected Earnings methodology provides an accounting-based approach that uses investment analyst estimates of return (net earnings) on book value (the equity portion of a company's overall capital, excluding long-term debt).

173. In Opinion No. 551, the Commission found that the results of MISO TOs' Expected Earnings analysis corroborated its determination that MISO TOs should be awarded an ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.[369] In doing so, the Commission reversed the Presiding Judge's rejection of

[367] Opinion No. 414-B, 85 FERC at 62,268.

[368] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 125.

[369] Opinion No. 551, 156 FERC ¶ 61,234 at P 230.

MISO TOs' Expected Earnings analysis. The Presiding Judge rejected the analysis because a critique by Dr. Morin took the position that the Expected Earnings analysis should be based on a sample of unregulated, rather than regulated companies, but MISO TOs' Expected Earnings analysis relied on regulated companies in the proxy group and their expert, Dr. Avera, was unable to sufficiently address Dr. Morin's critique.[370]

174. In Opinion No. 551, the Commission pointed out that Dr. Morin's critique was based on his concern that using the historical book ROE of regulated companies in the analysis would be based on past actions of regulatory commissions and would raise issues of circularity. The Commission found, however, that this concern was not present with respect to MISO TOs' Expected Earnings analysis because it was forward-looking.[371] The Commission further explained that the Expected Earnings analysis was useful in corroborating the results produced by the DCF model because investors rely on both the market cost of equity and the book return on equity in determining whether to invest in a utility.[372] CAPs, OMS, and RPGI request rehearing of Opinion No. 551's decision to consider the MISO TOs' Expected Earnings analysis.[373]

175. In the Initial Decision in the Second Complaint proceeding, the Presiding Judge similarly found that "an expected earnings [analysis] serves as a useful guide to placement of the Base ROE within the DCF-calculated zone of reasonableness to the extent it calculates the earnings on book value investors can expect to earn."[374] CAPs, OMS and JCA, RPGI, and Trial Staff filed exceptions to the Presiding Judge's decision to consider the MISO TOs' Expected Earnings analysis.[375]

176. In the Briefing Order, the Commission proposed to give the Expected Earnings model equal weight, along with the DCF model and CAPM, in establishing a composite zone of reasonableness to be used under the first prong of section 206.[376] For purposes of

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[370] *See* Initial Decision (I), 153 FERC ¶ 63,027 at P 325.

[371] *Id.* PP 231-232.

[372] *Id.* PP 234-236.

[373] *See, e.g.*, CAPs Rehearing Request at 25-41; OMS Rehearing Request at 16-20; RPGI Rehearing Request at 12-15.

[374] Initial Decision (II), 155 FERC ¶ 63,030 at P 515.

[375] *See, e.g.*, CAPs Br. on Exceptions at 79-85; OMS-JCA Br. on Exceptions at 5-6, 47-49; RPGI Br. on Exceptions at 64; Trial Staff Br. on Exceptions at 26-32.

[376] *See* Briefing Order, 165 FERC ¶ 61,118 at P 17.

establishing a new just and reasonable ROE where the existing ROE has been shown to be unjust and unreasonable (i.e., the second prong of the FPA section 206 analysis), the Commission proposed to use the Expected Earnings model, DCF model, CAPM, and Risk Premium model to produce four separate cost of equity estimates and then average the four estimates to produce the just and reasonable ROE.

177. In the briefs filed in response to the Briefing Order, the parties either generally opposed or supported the use of the Expected Earnings model in the Commission's revised ROE methodology. Those arguments and other relevant arguments in the records of these proceedings are summarized and addressed below.

B. Parties Opposing the Use of Expected Earnings

178. CAPs, Trial Staff, LPSC, and Alliant oppose using the Expected Earnings model in the Commission's revised ROE methodology. They all argue that the Expected Earnings model does not accurately reflect a utility's cost of equity because it is an accounting-based measure that does not reflect the rate of return that investors require to invest in the market-priced common equity capital of a utility.[377] CAPs assert that this is because an investor cannot purchase a utility's common stock at book value and must instead pay the prevailing market price for common equity, which means that expected earned return on book value is not indicative of what an investor can expect to earn on an investment in the utility's common stock nor what return an investor requires to invest in the utility's common stock.[378] Similarly, Trial Staff notes precedent in which the Commission found that "[a]ccounting rates of return are not reliable measures of the current market cost of capital, since they do not reflect the current market prices that are determined in competitive capital markets."[379]

179. Trial Staff also argues that the Expected Earnings model is not widely used by investors.[380] Trial Staff notes that Dr. Roger A. Morin's book, *New Regulatory Finance*, addresses a generic comparable earnings method, which is a backward-looking measure that is not the same model as the Expected Earnings model used by the MISO TOs in

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[377] *See, e.g.*, CAPs Initial Br. (I) at 40-44; CAPs Initial Br. (II) at 39-44; Trial Staff Initial Br. (I) at 8-9; Trial Staff Initial Br. (II) at 7-8; LPSC Initial Br. at 15-20; Alliant Reply Br. (I) at 5-6; Alliant Reply Br. (II) at 5-6.

[378] CAPs Initial Br. (I) at 41; CAPs Initial Br. (II) at 41.

[379] Trial Staff Initial Br. (I) at 8 (citing *Generic Determination of Rate of Return in Common Equity for Pub. Utils*., Order No. 420, FERC Stat. & Regs. at 31,344.

[380] Trial Staff Initial Br. (I) at 6-8; Trial Staff Initial Br. (II) at 5-7.

these proceedings. In addition, Trial Staff points to Dr. Morin's explanation of why multiple models should be used to estimate the cost of equity and notes that he cites Professor Eugene Brigham as stating that the CAPM, DCF, and Risk Premium models "typically are used" but not mentioning the Expected Earnings model.[381] Trial Staff further cites to an observation by Professor Brigham that the comparable earnings method has been "thoroughly discredited" and replaced by the market-oriented DCF, Risk Premium and CAPM models.[382] In addition, Trial Staff cites to a Federal Communications Commission report which explains that the two most commonly used methods for estimating the cost of equity are the DCF and CAPM models.[383] Accordingly, Trial Staff contends that there is little support for the notion that the Expected Earnings approach is widely used by investors.

180. LPSC similarly argues that evidence indicates that the Expected Earnings model is not used by investors. LPSC argues that the comparable earnings approach was grounded in the theory that the rate of return for utilities could be determined by examining the book returns of unregulated firms because their profitability would be limited by the forces of competition. LPSC asserts that, however, this analysis was made impractical because of differences in accounting between regulated and unregulated firms and the difficulty in measuring differences in risk between regulated and unregulated firms. LPSC argues that the alternative of using the comparable earnings of regulated utilities—like the analysis that was accepted in Opinion No. 551—conflicts with the essential premise of the comparable earnings approach because utilities do not operate in competition and therefore such an Expected Earnings analysis is not reliable. LPSC asserts that, if investors consider returns on book value at all, they do not consider it as a direct indication of returns on their investments because they cannot purchase stock at book value unless market price and book value happen to be exactly equal. In addition, LPSC cites to various academic sources which it asserts indicate that the Expected Earnings model is not used because of its flaws.[384] LPSC also asserts that, while

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[381] Trial Staff Initial Br. (I) at 6-7 (citing Morin at 430); Trial Staff Initial Br. (II) at 6 (citing same).

[382] Trial Staff Initial Br. (I) at 6-7 (citing Eugene F. Brigham, Dilip K. Shome & Steve R. Vinson, *Cost of Capital Estimation, The Risk Premium Approach to Measuring a Utility's Cost of Equity* 33 (1985)); Trial Staff Initial Br. (II) at 7 (citing same); LPSC Initial Br. at 1-2 (citing Eugene F. Brigham et al., *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, 14 Financial Management 33, 33 (1985)).

[383] Trial Staff Initial Br. (I) at 8 (citing *In re Connect Am. Fund*, 28 FCC Rcd. 7123, 7148 (2013)); Trial Staff Initial Br. (II) at 7 (citing same).

[384] LPSC Initial Br. at 1-4; 13-24.

Dr. Morin's academic text may explain the Expected Earnings model, he does not use it himself when presenting testimony concerning investor return requirements.[385] LPSC also states that, in proposing to abandon the use of book return to determine carriers' rate of return, the Federal Maritime Commission stated that a firm's accounting rates of return are not equivalent to the firm's true economic rate of return, because accounting and economic concepts of income and value are substantially different.[386] LPSC states that the Federal Maritime Commission adopted a final rule using the DCF model to determine rate of return.

181. CAPs argue that the Expected Earnings model produces an erroneously inflated measure of investors' required level of return for stocks whose market value exceeds their book value. CAPs assert that only when investors bid the stock price of a company to at or near its book value (i.e., a market-to-book ratio at or near 1.0) can the expected earned rates of return on the company's book value be considered a reasonable estimate of its cost of common equity capital, or investors' required return. CAPs further contend that the Expected Earnings model does not measure opportunity cost because the only opportunity cost available to investors is the market price at which they can actually purchase stock.[387]

182. CAPs also assert that the Expected Earnings model should not be used because it is inappropriately circular and potentially self-fulfilling. CAPs contend that this is the case because the *Value Line* projected earnings-to-book ratios are based on past allowed ROEs and therefore the Expected Earnings model's reliance on them will merely serve to perpetuate existing ROEs.[388]

183. RPGI argues that, if the Commission uses the Expected Earnings model in its revised methodology, it must consider market-to-book ratios in order to give the model an element of being a market-based approach. RPGI contends that, if the Commission

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[385] *Id.* at 16 (citing *Okla. Gas and Elec. Co.*, Cause No. PUD201700496 (Okla. Corp. Comm'n), Reb. Test. of Roger A. Morin at 33 (May 29, 2018) ("Q. Do you agree with Mr. Parcell's Comparable Earnings Analysis? A. *Although I myself do not rely on this accounting-based method*, I agree with Mr. Parcell's Comparable Earnings results.") (emphasis added)).

[386] *Id*. at 18-19, citing *Financial Reporting Requirements and Rate of Return Methodology in the Domestic Offshore Trades*, Proposed Rule, 59 Fed. Reg. 16,592 (1994).

[387] CAPs Initial Br. (I) at 41-43; CAPs Initial Br. (II) at 41-43.

[388] CAPs Reply Br. (I) at 37-38; CAPs Reply Br. (II) at 57-58.

does not consider market-to-book ratios then the Expected Earnings model should not be used.[389] LPSC similarly asserts that, if the Commission decides to use the Expected Earnings model, then it should adjust the analysis for market-to-book ratios or screen the group of unregulated firms based on market-to-book ratios.[390]

184. CAPs also argue that, if the Commission decides to use the Expected Earnings model, then it should implement certain adjustments. Specifically, CAPs argue that any Expected Earnings model should use the average of all available projected years' returns on book common equity, rather than just using the *Value Line* projection that is furthest out in time (that for 2018-2020). CAPS state that using all three forward projections provided by *Value Line*, including those for 2015 and 2016 would better reflect long-term expectations of per-book earnings. CAPs further contend that the Expected Earnings model should incorporate actual, realized returns for all available years because this will incorporate a measure of historical realism which will mitigate the risk that projections could reflect only short-run economic conditions that fail to represent long-term expectations.[391] CAPs also assert that an analysis of proxy company market-to-book ratios must be used in combination with the Expected Earnings model.[392] In addition, as discussed further below in section XII, CAPs argue that if the Expected Earnings model is used, then it should be given the least weight among the different financial models.[393]

185. Trial Staff witness, Mr. Keyton, asserts that, if the Commission uses the Expected Earnings model, then it should use the average of all three of the return on book value projections provided by *Value Line* rather than only the most distant projection, because this will moderate the impact of any irregular return on book value estimates that may be obtained from a single estimate.[394] Trial Staff and CAPs also both criticize the fact that

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[389] RPGI Initial Br. (I), Ex. RPG-17 at 25-26; RPGI Initial Br. (II), Ex. RPG-38 at 26.

[390] LPSC Initial Br. at 29.

[391] CAPs Initial Br. (I) at 44-46; CAPs Initial Br. (II) at 44-46; CAPs Reply Br. (I) at 38-39; CAPs Reply Br. (II) at 58-59.

[392] CAPs Reply Br. (I) at 39; CAPs Reply Br. (II) at 59.

[393] CAPs Initial Br. (I) at 46-48; CAPs Initial Br. (II) at 46-47; CAPs Reply Br. (I) at 40; CAPs Reply Br. (II) at 60.

[394] Trial Staff Initial Br. (I) at 18-19 and Keyton Aff. (I) ¶¶ 52-54; Trial Staff Initial Br. (II) at 18 and Keyton Aff. (II) ¶¶ 50-52.

the Expected Earnings model relies solely on *Value Line* growth estimates, which they contend are unreliable because they are made by a single analyst.[395]

C. Parties Supporting the use of Expected Earnings

186. MISO TOs argue that the Expected Earnings model is a useful tool for evaluating utilities' cost of equity[396] and that the Commission should reject all of the parties' arguments against using the Expected Earnings model.[397] MISO TOs note that CAPs cite to Order No. 461[398] for the proposition that *Hope* and *Bluefield* require returns to reflect the market cost of equity and then argue that the Commission has not justified the use of the Expected Earnings model because it is based on accounting rates of return that do not estimate the market cost of capital. MISO TOs argue that CAPs overstate the importance of Order No. 461's reference because the mere fact that the Commission previously found compelling reasons to focus on the market cost of equity does not tie the Commission's hands today. MISO TOs assert that ratemaking is not a science and that the Commission uses models only to inform, not rigidly determine an appropriate ROE. MISO TOs further contend that, in the sentence immediately following CAPs' selected passage in Order No. 461, the Commission stated that it will "take into account non-cost factors in setting an allowed rate of return in an individual case if circumstances warrant."[399]

187. MISO TOs also note CAPs' citation to Opinion No. 429 but assert that, while the Commission declined to rely solely on the comparable earnings method to establish ROE in that case, it did not hold that the FPA forecloses non-market-based methods for developing just and reasonable returns. MISO TOs argue that the Commission only noted that it "*currently* favors market-oriented methodologies (the DCF methodology in

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[395] CAPs Initial Br. (I) at 43; CAPs Initial Br. (II) at 43; Trial Staff Initial Br. (I) at 9-10; Trial Staff Initial Br. (II) at 9.

[396] MISO TOs Initial Br. (I) at 4; MISO TOs Initial Br. (II) at 6; MISO TOs Reply Br. (I) at

[397] MISO TOs Reply Br. (I) at 35-36; MISO TOs Reply Br. (II) at 35-36.

[398] *Generic Determination of Rate of Return on Common Equity for Pub. Utils.*, Order No. 461, 37 FERC ¶ 61,287, FERC Stats. & Regs., Regs Preambles ¶ 30,722 (1986) (Order No. 461), *reh'g denied*, Order No. 461-A, 38 FERC ¶ 61,160 (1987).

[399] MISO TOs Reply Br. (I) at 37 (citing Order No. 461, FERC Stats. & Regs., Regs Preambles ¶ 30,722 at 30,499); MISO TOs Reply Br. (II) at 37 (citing same).

particular)."[400] MISO TOs argue that the Commission is now merely proposing a different, equally legitimate, approach in light of different circumstances.

188. In addition, MISO TOs take issue with LPSC's citation to the Federal Maritime Commission's proposal of a new rule as support for LPSC's argument that the Expected Earnings model does not utilize accepted financial theory. MISO TOs argue that the statement that LPSC cites is irrelevant because courts had in fact previously upheld the Federal Maritime Commission's use of a purely accounting-based, comparable earnings test to determine rates of return under a "just and reasonable" standard akin to that of the FPA.[401] MISO TOs contend that, therefore, the Expected Earnings model's reliance on accounting data does not preclude the Commission from using the model in its ROE methodology.[402]

189. MISO TOs' witness, Mr. McKenzie, similarly asserts that the purpose of the Expected Earnings model is not to derive a market cost of equity. He contends that this is an advantage of the model because it avoids the complexities, controversies, and limitations of capital market methods and instead focuses on expected earned returns on book equity, which are readily available to investors. MISO TOs also assert that the fact that the Expected Earnings model does not rely on market data is, in fact, a sound reason for the Commission to include the model in its ROE determinations. MISO TOs argue that the market-based methods all involve complexities, controversies, and limitations that the Expected Earnings does not share. Mr. McKenzie asserts that, because no single approach can accurately reflect investors' required return, the Commission correctly determined that considering the results of alternative methods provides a more accurate basis on which to determine a just and reasonable ROE and reliance on the Expected Earnings approach is consistent with this logic. Mr. McKenzie further contends that, because regulators establish the allowed return on the book value of a utility's investment—not the return that investors earn in the capital markets—the Expected

[400] MISO TOs Reply Br. (I) at 38 (citing *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100, at 61,362 (1998) (Opinion No. 429) (emphasis added by MISO TOs)); MISO TOs Reply Br. (II) at 38 (citing same).

[401] MISO TOs Reply Br. (I) at 38-39 (citing *Matson Navigation Co. v. Fed. Mar. Comm'n*, 959 F.2d 1039, 1041, 1043 (D.C. Cir. 1992); MISO TOs Reply Br. (II) at 38-39 (citing same).

[402] MISO TOs Reply Br. (I) at 38-39; MISO TOs Reply Br. (II) at 38-39.

Earnings model provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.[403]

190. MISO TOs also assert that the circularity criticisms of the Expected Earnings model are meritless. MISO TOs argue that the Expected Earnings model is not circular because it relies on forward-looking, expected returns on book equity, and circularity is an issue only with the comparable earnings model, which relies on historical earnings on book equity. MISO TOs also contend that Trial Staff and LPSC are mistaken in asserting that Dr. Morin does not support use of the Expected Earnings model. MISO TOs argue that they disregard his explanation that the comparable earnings model is highly meaningful. Moreover, MISO TOs contend that, while Trial Staff is correct that Dr. Morin does not explicitly mention "expected earnings," the comparable earnings model that he does discuss is the forward-looking version of the Expected Earnings model. MISO TOs also state that Trial Staff and LPSC ignore the close relationship of the comparable earnings approach to the capital attraction standards of *Hope* and *Bluefield*.[404] Mr. McKenzie states that "virtually every measure of future financial performance—including cash flow measures, profitability, and dividend policies—is impacted by the ROE established by regulators"[405] and concludes that, therefore the Expected Earnings model is no more susceptible to circularity concerns than the DCF.

191. In addition, MISO TOs argue that evidence demonstrates that investors rely on the utilities' expected earnings. MISO TOs assert that investors understand that regulators establish rates of return on book equity and they do not and cannot determine a rate of return on the market value of a utility's equity. MISO TOs contend that the evidentiary records in these proceedings include numerous examples of investment advisories and other publications that provide estimates of utilities' returns on equity, including returns on book value of utilities' assets.[406] They assert that Mr. McKenzie's reply affidavit

[403] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 62-67; MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 62-67.

[404] MISO TOs Reply Br. (I) at 42-43; MISO TOs Reply Br. (II) at 42-43.

[405] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 72; MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 72.

[406] MISO TOs Reply Br. (I) at 43-44; MISO TOs Reply Br. (II) at 43-44.

includes additional examples of the investment community's recognition of the relevance of returns on book value.[407]

192. Mr. McKenzie cites an S&P report as demonstrating the relevance of earned returns on book value in highlighting the primary credit considerations in the utility industry. In particular, he points to a statement in the report that "'required rate of return on equity investment is closely linked to a utility company's profitability.'"[408] Mr. McKenzie points to the report's statement that "'the regulator ultimately bases its decision on an authorized ROE,'" but "different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of- service-based utilities centers on the utility's ability to consistently earn the authorized ROE.'"[409] Mr. McKenzie contends that this demonstrates that S&P's view is that earned return on book value may provide better insight into the financial health of the utility because it reflects the end-result of regulation, not the theoretical outcome implied by an authorized ROE.[410]

193. Mr. McKenzie argues that Moody's also recognizes the relevance of returns on book value in its assessment of a utility's future prospects. He cites a report in which Moody's stated that, while "'[t]he authorized ROE is a popular focal point in many regulatory rate case proceedings,'" it is the case that "'earned ROEs, as reported by

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[407] MISO TOs Reply Br. (I) at 44 (citing MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 69-70); MISO TOs Reply Br. (II) at 43-44 (citing MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 69-70).

[408] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 69 (citing S&P Global, *Utilities: Key Credit Factors For The Regulated Utilities Industry,* Criteria Corporates (Nov. 19, 2013); https://www.standardandpoors.com/en_US/web/guest/article/-/view/type/HTML/id/2189281); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 69 (citing same).

[409] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 69-70 (citing S&P Global, *Utilities: Key Credit Factors For The Regulated Utilities Industry,* Criteria Corporates (Nov. 19, 2013); https://www.standardandpoors.com/en_US/web/guest/article/-/view/type/HTML/id/2189281); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 69-70 (citing same).

[410] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 70; MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 70.

utilities and adjusted by Moody's,' are a key gauge of financial performance."[411] In addition, Mr. McKenzie cites a CFRA publication which he contends "highlighted the relevance of returns on book equity to investors." He cites the following portion of the publication as supporting this contention

> If a utility's ROE is too low, the analyst must determine if it was caused by mild weather or the absence of a needed rate hike – or if the utility is poorly operated. Conversely, an ROE that is too high could cause regulators to seek a rate cut. For firms in the S&P Composite 1500 electric utilities index, the average ROE generally ranges between 10% and 13%, although the average has trended lower in the past few years.[412]

194. As additional evidence that the Expected Earnings model has been recognized as a meaningful ROE methodology, Mr. McKenzie cites to a 1991 survey by the National Association of Regulatory Commissioners (NARUC) in which it reported that 19 regulatory jurisdictions cited the comparable earnings approach as a primary method favored in determining the allowed ROE, while an additional 16 jurisdictions reported that this approach was considered along with the results of other methods.[413] He also notes that the Virginia State Corporation Commission is required by statute to consider the earned returns on book value of electric utilities in its region, which establish lower and upper boundaries for the allowed ROE.[414] In addition, Mr. McKenzie points to a textbook prepared by Mr. Parcell for the Society of Utility and Regulatory Financial

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[411] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 70 (citing Moody's Investors Service, Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles, Sector In-Depth, at 5 (Mar. 10, 2015)); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 70 (citing same).

[412] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 70-71 (citing CFRA, Electric Utilities, Industry Surveys 50 (Aug. 2018)); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 70-71 (citing same).

[413] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 67-68 (citing Nat'l Ass'n of Regulatory Util. Comm'rs, *Utility Regulatory Policy in the U.S. and Canada, 1995-1996* (Dec. 1996)); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 67-68 (citing same).

[414] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 68 (citing Virginia Code § 56-585.1.A.2.a)); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 68 (citing same).

Analysts which Mr. McKenzie asserts "observes that the amount of subjective judgment required to implement this method is 'minimal,' particularly when compared to the DCF and CAPM methods."[415]

195. MISO TOs also disagree with LPSC's contention that Dr. Morin says that the Expected Earnings model requires a proxy group of non-regulated companies. MISO TOs assert that, to the contrary, Dr. Morin only observed that the backward-looking, comparable earnings model "usually" uses a sample of unregulated companies. MISO TOs argue that, because Dr. Morin did not even explicitly address the Expected Earnings model, the "usual" application of a different methodology does not indicate any error in the Commission's proposal.[416]

196. MISO TOs further assert that LPSC's claim that the Expected Earnings model reflects the results of inconsistent accounting does not establish that the Expected Earnings model is unreliable. MISO TOs claim that LPSC provides no evidence that any of the data relied upon in the Expected Earnings analyses in these proceedings is inaccurate or unreliable in any way.[417]

197. MISO TOs also dispute that the Expected Earnings model is unreliable when utilities' market-to-book ratios are greater than one. MISO TOs argue that, in Opinion No. 551, the Commission explained that investors rely upon the return on book equity to determine the opportunity cost of investing in a particular company, and investors rely upon Expected Earnings analysis for this purpose without attempting to convert that opportunity cost into the current market cost of equity.[418] MISO TOs further assert that LSPC fails to mention that Dr. Morin rejects the notion that regulators' ROE decisions should consider market-to-book ratios.[419] MISO TOs' witness Mr. McKenzie contends that market-to-book ratios of greater than one are not unusual and that if, as CAPs and

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[415] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 68 (citing David C. Parcell, *The Cost of Capital: A Practitioner's Guide* 115-16 (1997)); MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 68 (citing same).

[416] MISO TOs Reply Br. (I) at 44; MISO TOs Reply Br. (II) at 44.

[417] MISO TOs Reply Br. (I) at 45-47; MISO TOs Reply Br. (II) at 45-47.

[418] MISO TOs Reply Br. (I) at 47-48 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 234); MISO TOs Reply Br. (II) at 47-48 (citing same).

[419] MISO TOs Reply Br. (I) at 48; MISO TOs Reply Br. (II) at 48.

LPSC assert, an appropriate market-to-book ratio for utilities is at or near 1.0, then this would imply that MISO TOs should incur significant capital losses.[420]

198. MISO TOs support the use of *Value Line* estimates in the Commission's proposed Expected Earnings model. MISO TOs dispute CAPs' argument that, because the Commission has declined to use *Value Line*'s estimates in the DCF model, the Commission should not rely upon *Value Line*'s five-year average earnings estimates in the Expected Earnings model. MISO TOs state that the Commission has declined to accept *Value Line* earnings growth rates in its DCF model on the ground that such estimates are created by a single analyst. MISO TOs note that CAPs point to the Commission's observation that its decision to abandon exclusive reliance on the DCF model was based in part on evidence that a single analyst is the source of many IBES earnings estimates. MISO TOs argue that the proper response to this is not to ignore all single-analyst estimates, but to consider additional, multiple estimates, to minimize the risk that unreliable data may distort the results of a particular model. MISO TOs also disagree with CAPs' alternative contention that the Commission should require the Expected Earnings model to average *Value Line*'s shorter-term earnings estimates with the five-year estimates. MISO TOs assert that the Commission rejected this suggestion in Opinion No. 551 and no party has offered any basis for the Commission to revisit that conclusion.[421]

199. In addition, MISO TOs argue that the Commission should reject CAP's proposal to use actual realized returns for all available years to incorporate historical realism in the Expected Earnings model. MISO TOs contend that using estimates of future earnings and book equity, rather than historical data, is what distinguishes the Expected Earnings model from the comparable earnings method and thus historical data should not be used.[422]

D. Commission Determination

200. In the Briefing Order, the Commission proposed to use the Expected Earnings model because the record in these proceedings included the Expected Earnings model as one of the methods that "investors may use to estimate the expected return from an

[420] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 78-89; MISO TOs Reply Br. (II), App. 2 McKenzie Reply Aff. (II) at 78-89.

[421] MISO TOs Reply Br. (I) at 48-50; MISO TOs Reply Br. (II) at 48-50.

[422] MISO TOs Reply Br. (I) at 50-51; MISO TOs Reply Br. (II) at 50-51.

investment in a company."[423] In Opinion No. 551, the Commission found that the Expected Earnings model was useful in corroborating the results produced by the DCF model[424] and, in the Initial Decision in the Second Complaint proceeding, the Presiding Judge similarly found that the Expected Earnings model was a "useful guide to placement of the Base ROE within the DCF-calculated zone of reasonableness to the extent it calculates the earnings on book value investors can expect to earn."[425] However, we now find that, in light of the record as supplemented after issuance of the Briefing Order, it is not appropriate to use the Expected Earnings model in our new base ROE methodology.

201. In particular, we find that the record does not support departing from our traditional use of market-based approaches to determine base ROE.[426] Under the market-based approach, the Commission sets a utility's ROE to equal the estimated return that investors would require in order to purchase stock in the utility at its current market price. In *Hope*, the Supreme Court explained that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[427] In order to determine this, we must analyze the returns that are earned on "investments in other enterprises having corresponding risks," but investors cannot invest in an enterprise at book value and must instead pay the prevailing market price for an enterprise's equity. As a result, the expected return on a utility's book value does not reflect "returns on investments in other enterprises" because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, we find that relying on the Expected Earnings model would not satisfy the requirements of *Hope*.

202. The return on book value is also not indicative of what return an investor requires to invest in the utility's equity or what return an investor receives on the equity

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[423] Briefing Order, 165 FERC ¶ 61,118 at P 36.

[424] Opinion No. 551, 156 FERC ¶ 61,234 at P 230.

[425] Initial Decision (II), 155 FERC ¶ 63,030 at P 515.

[426] *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Order No. 489, FERC Stats. & Regs. ¶ 30,795 at 30,993, *reh'g denied*, Order No. 489-A, 42 FERC ¶ 61,390 (1988) ("There is compelling economic justification for relying on the market cost of capital as the standard for rate of return decisions. Furthermore, a market cost of capital approach addresses both the comparable earnings and attraction of capital standards of the *Hope* decision.").

[427] *Hope*, 320 U.S. at 603.

investment, because those returns are determined with respect to the current market price that an investor must pay in order to invest in the equity. As CAPs similarly explain, "Because an investor cannot purchase a utility's common stock at book value and must instead pay the prevailing market price for common equity, the utility's expected earned return on book value is indicative of neither what an investor can expect to earn on an investment in the utility's common stock nor what return an investor requires to invest in the utility's common stock."[428] Accordingly, return on book value does not reflect "the return to the equity owner" that we must ensure is "commensurate with returns on investments in other enterprises"; therefore we find that this model is not useful in ensuring that the standards of *Hope* are satisfied.

203. MISO TOs argue that the fact that the Expected Earnings model does not rely on market data is a sound reason for the Commission to include the model in its ROE determinations. MISO TOs assert that the Expected Earnings model avoids the complexities and opportunities for controversy that are implicated by the market-based models. MISO TOs contend that the Expected Earnings model relies on the straight-forward concept that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return.[429] To make a similar point, MISO TOs' witness Mr. McKenzie points to a textbook prepared by Mr. Parcell for the Society of Utility and Regulatory Financial Analysts which Mr. McKenzie asserts "observes that the amount of subjective judgment required to implement this method is 'minimal,' particularly when compared to the DCF and CAPM methods."[430]

204. While it may be true that the Expected Earnings model does not involve the same complexities as the market-based approaches, we find that this is because it does not reflect a utility's cost of equity. It is simpler because it does not consider the market price that an investor must pay to make its investment and other factors such as projected growth rates for the subject utility. Factors such as these—in particular the market price that an investor must pay for an investment, which is the basis for determining the return on that investment—are critical to determining a utility's cost of equity. While it may be simpler to use a model that does not consider such factors, doing so renders that model unable to effectively estimate the rate of return that investors require to invest in the market-priced common equity capital of a utility, which is the utility's cost of equity

[428] CAPs Initial Br. (I) at 41; CAPs Initial Br. (II) at 41.

[429] MISO TOs Reply Br. (I) at 39 and App. 2, McKenzie Reply Aff. (I) at 65; MISO TOs Reply Br. (II) at 39 and App. 2, McKenzie Reply Aff. (II) at 65.

[430] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 68 (citing David C. Parcell, *The Cost of Capital: A Practitioner's Guide* 115-16 (1997)); MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 68 (citing same).

capital. We find that it is not appropriate to use a model that does not accurately measure the "return to the equity owner" as required by *Hope* merely because it may be simpler to administer. We are cognizant of the administrative burden that is placed on parties to evaluate models that are used in analyzing ROEs, but the mere simplicity of one model as compared to others does not justify using that model if it does not assist us in ensuring that returns to equity owners are just and reasonable.

205. Moreover, we find that the record demonstrates that the Expected Earnings model does not identify investments of comparable risk and which alternatives will have a higher expected return as MISO TOs' witness Mr. McKenzie indicates.[431] In particular, because the Expected Earnings model measures returns on book value, without consideration of what market price an investor would have to pay to invest in the relevant company, it does not accurately measure the investor's expected returns on its investment. In order to assess what return investors will receive, they must know the market price of the equity that they are purchasing. For example, if two companies each have book value of $100 and expected returns on that book value of 10 percent, or $10, over the next year, then they would appear to be equally attractive investments to an investor based on the Expected Earnings model. However, if the market price to purchase the first company's stock is $20 and the market price to purchase the second company's stock is $40, then the first company would obviously be a more attractive investment. Thus, contrary to Mr. McKenzie's characterization, investors in such a situation would not be able to determine what "the alternative with the higher expected return" is with the Expected Earnings model.

206. MISO TOs also argue that the fact that the majority of stocks, including utility stocks, sell substantially above the company's book value supports the use of the Expected Earnings Model.[432] MISO TOs' witness, Mr. McKenzie, points out that *Value Line* reports that approximately 1500 of the roughly 1700 stocks it follows have market-to-book ratios above one, and he cited evidence that utility stocks have an average market-to-book ratio of 2.1.[433] Mr. McKenzie asserts that, in these circumstances, an ROE equal to the current market cost of equity as determined under the DCF model will not produce sufficient earnings to support the utility's current stock price. Mr. McKenzie points out that the Commission calculates the dollar return included in a utility's rate base by multiplying the book value of the rate base by the percentage ROE determined by the

[431] MISO TOs Reply Br. (I) at 39 and App. 2, McKenzie Reply Aff. (I) at 65; MISO TOs Reply Br. (II) at 39 and App. 2, McKenzie Reply Aff. (II) at 65.

[432] MISO TOs Reply Br. (I) at 47-48; MISO TOs Reply Br. (I) at 47-48.

[433] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 81-82; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 81-82.

Commission. He then provides a numerical example that purports to show that, when a utility's market-to-book ratio is above one, this calculation will not produce a sufficient dollar return to allow the utility to continue to pay the same level of dividends and retain the same level of earnings to fund growth as the investor assumed in performing its DCF analysis and evaluating whether to purchase the stock.[434] As a result, according to Mr. McKenzie, the DCF model will not provide a return sufficient to support the utility's current stock price.[435] Mr. McKenzie asserts that, by contrast, the Expected Earnings model calculates the projected returns on the utility's book equity that support the investors' expectations underlying the current market price of the stock. As a result, Mr. McKenzie contends the Expected Earnings model provides a direct guide to ensure that the ROE allowed by the Commission is similar to the returns that investors expect other utilities of comparable risk will earn on the book value of their invested capital.[436]

207. The MISO TOs' concerns about market-to-book ratios in excess of one and maintaining the current stock values of public utilities do not justify use of the Expected Earnings model. The Commission is not obligated to set ROEs so as to maintain current stock values.[437] As the Supreme Court held in *Hope*, the "fair value" of a regulated enterprise "is the end product of the process of ratemaking, not the starting point . . . The heart of the matter is that rates cannot be made to depend on 'fair value' when the value of the going enterprise depends upon earnings under whatever rates are anticipated."[438] Consistent with this holding in *Hope*, the Commission has stated, "The market value of an enterprise or its common stock depends upon its earnings or anticipated earnings,

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[434] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 83; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 83.

[435] Mr. McKenzie also cites a 1970 scholarly article raising similar concerns about the DCF model "in the early days before the DCF became a regulatory mainstay." MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 84 (citing Walter A. Morton, *The Investor Capitalization Theory of the Cost of Equity Capital*, Land Econ. 248-63 (Aug. 1970)); MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 84 (citing same).

[436] *Id*. at 83-84.

[437] *Illinois Bell Telephone Co. v. FCC*, 988 F.2d 1254 (D.C. Cir. 1993) (*Illinois Bell*) (affirming the FCC's rejection of the same contention concerning use of the DCF model when market-to-book ratios are above one as the MISO TOs make here, and stating that the FCC "has no obligation to maintain the current market value on investors' property.").

[438] *Hope*, 320 U.S. at 601.

which in turn depend upon the rates allowed. Thus, market value is the result of the ratemaking process and may not properly be the beginning of that process as well."[439]

208. In any event, there is no evidence that the Commission's use of the DCF model to determine ROEs based on the current market cost of capital has provided insufficient returns to support proxy company stock values or had a tendency to drive market-to-book ratios down to one. In fact, market-to-book ratios of the proxy companies have been consistently above one since the 1980s, a period during which the Commission solely used the DCF model to determine ROEs.[440] Moreover, the public utility companies for which the Commission sets rates are not publicly traded and thus do not have any market-determined stock values. Hence, there is no observable market-to-book ratio specifically applicable to the electric transmission business for which we are establishing an ROE. The publicly-traded companies in the proxy group are generally holding companies, which not only have regulated electric transmission business but also other businesses that are not subject to cost-based regulation.[441] Therefore, the proxy company market-to-book ratios may exceed one primarily because of the value investors see in their non-electric transmission businesses.[442] We recognize that, in an environment where the market-to-book ratios of publicly-traded companies are generally above one, it would be unreasonable to adopt an ROE policy that resulted in capital losses for investors in order to drive market-to-book ratios that are currently above one down to one.[443] However, the record before us does not contain evidence that our longstanding policy of determining ROE based on the current market cost of equity is having this effect. In these circumstances, we see no basis to change that policy in order to use the Expected Earnings model.

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[439] Order No. 489, FERC Stats. & Regs. ¶ 30,795 at 30,994; s*ee also Orange and Rockland Utilities, Inc*., Opinion No. 314, 44 FERC ¶ 61,253 at 61,952*, reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252 (1988).

[440] Morin at 377. The market-to-book ratios of the proxy group companies in the First Complaint proceeding range from 1.17 to 2.55. Ex. JCI-100 at 35. The market-to-book ratios of the proxy group companies in the Second Complaint proceeding range from 1.15 to 3.38. Ex. JCI-200 at 33 n. 47.

[441] CAPs Initial Br. (I), Ex. JCI-100 at 36; CAPs Initial Br. (II), Ex. JCI-200 at 35.

[442] *See Illinois Bell*, 988 F.2d at 1261 (stating that the telephone companies there at issue also had unregulated assets, and appreciations in the value of the unregulated assets could account for the market-to-book ratios above one).

[443] *See* Morin at 376-378.

209. We agree with MISO TOs that the Commission is not necessarily required to rely on only market-based methods to determine ROEs merely because it previously found that such an approach was appropriate. If, for example, facts and circumstances before the Commission change in a manner that would allow the Commission to provide a reasoned explanation for departing from this precedent, then the Commission could depart from this precedent. However, the mere fact that the Commission can depart from precedent such as Order No. 461 and Opinion No. 429 does not necessarily mean that it should. Here, we find that the record does not demonstrate that it is appropriate to rely on the Expected Earnings model in our ROE analysis and we find, consistent with our existing precedent, that it is appropriate to rely on market-based methods in our ROE determinations. Similarly, we agree with MISO TOs that the fact that the Federal Maritime Commission criticized using an accounting-based rate of return method does not preclude this Commission from using such a method. However, the fact that we are not precluded from using an accounting-based method does not mean that we must use such a method. As discussed herein, we find that, on balance, this evidence and the other record evidence in these proceedings demonstrates that the Expected Earnings approach is not appropriate for us to use in our ROE analysis.

210. In the Briefing Order, the Commission noted that the returns on book equity that investors expect to receive "are relevant to determining that utility's cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk."[444] The Commission further stated that "Because investors rely on Expected Earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in determining a utility's ROE."[445] In light of the record in these proceedings as supplemented after issuance of the Briefing Order, we find that there is not sufficient record evidence to conclude that investors rely on the Expected Earnings analysis to estimate the opportunity cost of investing in a particular utility as compared to other companies. As parties have noted, investors cannot purchase equity at book value;[446] therefore, although book value and returns on book equity may be useful data points for investors, they do not reflect an opportunity for investment that can be characterized as an opportunity cost. In addressing this point, CAPs' witness Mr. Solomon cites to a similar explanation of the point made by Dr. Morin that "Accounting rates of return are not opportunity costs in the economic sense, but reflect

[444] Briefing Order, 165 FERC ¶ 61,118 at App.

[445] *Id.*

[446] *See, e.g.*, CAPs Initial Br. (I) at 41, Ex. JCI-100 at 30; CAPs Initial Br. (II) at 41, Ex. JCI-200 at 29.

the average returns earned on past investments and hence reflect past regulatory actions . . . Investors can only purchase new shares of common stock at current market prices and not at book value."[447] Moreover, as we discuss further below, there is insufficient record evidence to demonstrate that investors rely on the Expected Earnings model.

211. Record evidence also provides an example of how returns on book equity fail to reflect the returns that investors require to invest in a given company and thus, fail to reflect the opportunity costs of investing in one company as opposed to others. As CAPs explain, when the market value of a company's equity exceeds its book value—i.e., when its market-to-book ratio exceeds 1.0—this means that investors' required rate of return for investing in the equity is less than the expected earnings on book value for that company.[448] CAPs' witness Mr. Solomon then details the market-to-book ratios for the proxy groups used by Dr. Avera in the First Complaint and Second Complaint proceedings, finding that the ratios ranged from 1.17 to 2.55 for the proxy groups in both proceedings, with 30 of the 39 companies in the First Complaint proxy group having ratios at or above 1.50 (with an average of 1.80) and 23 of the 32 companies in the Second Complaint proxy group having ratios at or above 1.50 (with an average of 1.70).[449] Accordingly, the record demonstrates that investors' required rate of return for investing in the equity of all of the proxy group companies in both of these proceedings is less than the return on the book value of the equity of those companies. Therefore, the return on the book value measured by the Expected Earnings model overstates the investors' required rate of return for investing in the proxy group companies and as a result it does not reflect investors' opportunity cost of investing in one proxy group company as opposed to another.

212. In the Briefing Order, the Commission stated that a primary reason for proposing to average the results of the DCF analysis with the results of the CAPM, Expected Earnings, and Risk Premium analyses is that investors use those models, in addition to

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[447] CAPs Initial Br. (I), Ex. JCI-100 at 31 (citing Morin at 393); CAPs Initial Br. (II), Ex. JCI-200 at 30.

[448] *See* CAPs Initial Br. (I) at 42-43, Ex. JCI-100 at 30-31; CAPs Initial Br. (II) at 42, Ex. JCI-200 at 29-30; Opinion No. 314, 44 FERC at 61,952 ("[W]hen the price-to-book ratio is greater than one, the rate of return investors expect O&R to earn on common equity is greater than the rate of return investors require from their investment in O&R's common stock.").

[449] CAPs Initial Br. (I) at 42-43, Ex. JCI-100 at 35; CAPs Initial Br. (II) at 42-43, Ex. JCI-200 at 34.

the DCF methodology, to inform their investment decisions.[450] Upon review of the record, as supplemented after issuance of the Briefing Order, we find that this statement may not be true with respect to the Expected Earnings model. MISO TOs cite numerous pieces of evidence of "investment advisories and other publications that provide estimates of utilities' returns on equity, including returns on book value of utilities' assets."[451] This evidence cited by the MISO TOs shows that investors examine expected earnings (future profits). However, looking at the future earnings of a company is not the same as determining a company's cost of capital or making investment decisions based on the earnings per book value calculations in the Expected Earnings model. Additionally, there is no evidence that such information is useful to investors in determining their required return from an investment in a particular company independent of the stock price, which the Expected Earnings model ignores. Below we examine the specific evidence that MISO TOs' claim demonstrates that investors use the Expected Earnings model.

213. Exhibit No. MTO-43 in the First Complaint proceeding, a Wolf Research report, discusses Commission and state regulated ROE determinations. Exhibit No. MTO-44 in the First Complaint proceeding, a UBS Global Research brief, also discusses Commission ROE policy without mentioning non-DCF approaches or book value. Exhibit No. MTO-45 in the First Complaint proceeding, another UBS Global Research brief, similarly merely discusses potential changes to the Commission's ROE policy with no mention of use of earnings per book value or other approaches. Although investors are obviously interested in what ROE the Commission may approve in pending rate proceedings, that fact does not support a finding that investors use the Expected Earnings model to determine their required returns on investments in public utilities.

214. Exhibit No. MTO-54 in the First Complaint proceeding, the *Value Line* portion of Exhibit No. S-3 cited by MISO TOs, and pages 41-85 of Exhibit No. JCI-3 in the Second Complaint proceeding—all *Value Line* summary PDFs for proxy group companies—include dozens of financial metrics and brief discussions of major issues surrounding companies. Book value and book value per share are among the information provided, as well as return on total capital. However, total capital in this instance differs from net plant, which is listed separately and is more analogous to book value. In any event, the listing of a relevant metric among dozens does not indicate that investors use it independently to determine their required return on their investments in particular companies. The Barron's report in Exhibit No. S-3 discusses key financial metrics including earnings per share and dividend yield, and explicitly discusses these metrics

[450] Briefing Order, 165 FERC ¶ 61,118 at P 46.

[451] MISO TOs Reply Br. (I) at 43-44; MISO TOs Reply Br. (II) at 43-44.

with respect to the share price that investors see.[452] It does not discuss book value or illustrate that investors determine the cost of equity or make purchase decisions using the Expected Earnings model. Pages 3-4 of Exhibit No. JCI-12 in the Second Complaint proceeding, a Moody's report, examines the impact of Commission proceedings on American Transmission Company. It makes no mention of book value and merely opines on how changes in authorized ROEs could affect future earnings. The information in Exhibit No. JCI-13 in the Second Complaint provides a similar analysis for Ameren Illinois.

215. MISO TOs' witness Mr. McKenzie asserts that an S&P Global report in Exhibit No. MTO-74 in the Second Complaint proceeding indicates that the earned return on book value may provide better insight into the financial health of the utility because it reflects the end-result of regulation, not the theoretical outcome implied by an authorized ROE. He also maintains that Moody's recognizes the relevance of returns on book value when it explains that earned ROEs, rather than authorized ROEs, are a "key gauge of financial performance."[453] However, we agree with Trial Staff that the record lacks evidence that S&P and Moody's use this information to estimate the cost of equity.[454] First, we disagree with MISO TOs that S&P's statement that "different factors [other than ROEs] such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service –based utilities centers on the utility's ability to consistently earn the authorized ROE"[455] indicates that S&P examines earnings per book value. Whether a utility actually earns the authorized ROE can be determined by comparing actual earnings with the earnings implied by the authorized ROE, which is independent of book value. In fact, the only mention of book value in the S&P article is, when explaining the usefulness of earnings before interest, tax, depreciation and amortization, the statement that "the book value of capital does not always reflect true earning potential." Similarly, the Moody's reference

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[452] Ex. S-3 at 1-3.

[453] MISO TOs Reply Br. (I), App. 2, McKenzie Reply Aff. (I) at 70; MISO TOs Reply Br. (II), App. 2, McKenzie Reply Aff. (II) at 70.

[454] *See* Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 5; Trial Staff Reply Br. (II), Keyton Reply Aff. (II) at 5.

[455] MISO TOs Reply Br. (I), App. 2, McKenzie Reply Aff. (I) at 69-70 (citing S&P Global, *Utilities: Key Credit Factors For The Regulated Utilities Industry*, Criteria Corporates (Nov. 19, 2013), https://www.standardandpoors.com/en_US/web/guest/article/-/view/type/HTML/id/2189281)); MISO TOs Reply Br. (II), App. 2, McKenzie Reply Aff. (II) at 69-70 (citing same).

to the stability of "earned ROEs" as reported by utilities does not clearly indicate that it is earned returns on book value.

216. Even if Mr. McKenzie's inferences regarding the usefulness of earnings as related to book value to assess the financial health of a utility are correct, that fact is not indicative that such information is used by investors independently of price to determine their required returns. As discussed above, the Commission relies on the market cost of capital as the standard for its rate of return decisions. This approach requires us to estimate the return that investors would require in order to purchase stock in the utility at its current market price. We have determined that, for this purpose, we should look to the methods that investors use to determine their required return on an investment in public utilities, including the DCF and CAPM models. However, there is nothing in the S&P and Moody's articles cited by Mr. McKenzie to indicate that investors look to earnings on book value to determine their required return on an investment. Credit rating agencies, who are not investors, may use such information to inform their assessment of utilities' risk or financial strength. As Mr. McKenzie states, S&P uses this metric to assess utilities' "financial health."[456] However, there is no evidence that they use such metrics to determine the cost of capital of utilities or to calculate return on an investment.

217. Looking at earned return on book value is not the same as conducting an Expected Earnings analysis to determine the applicable cost of capital. Investors observe many financial metrics, including metrics such as price to earnings ratios and free cash flow, which are not independently bases for determining an entity's cost of equity or investment decisions. When an investor makes an investment decision, a fundamental consideration is the cost to the investor to make the investment—i.e., the market price that the investor must pay for the investment. The Expected Earnings analysis does not take this fundamental consideration into account and thus it does not reflect how an investor would make an investment decision. MISO TOs' citations to evidence that merely references book value or earnings on book value among various other financial metrics or in the context of credit rating analyses does not demonstrate that investors would use the earnings on book value results of an Expected Earnings analysis to make investment decisions without considering the market price of the investment.

218. The academic literature and testimony by academics cited in the record also indicates that investors do not commonly use the Expected Earnings model to estimate utilities' cost of equity. Trial Staff states that the Briefing Order cites Exhibit No. MTO-1 in the First Complaint proceeding as support for the proposition that investors base their decisions on models that include the Expected Earnings model. Trial Staff argues that, however, that exhibit, which in turn cites Dr. Morin's *New Regulatory*

[456] MISO TOs Reply Br. (I), App. 2, McKenzie Reply Aff. (I) at 70; MISO TOs Reply Br. (II), App. 2, McKenzie Reply Aff. (II) at 70.

Finance, does not support this proposition. Trial Staff asserts that Dr. Morin does not mention the Expected Earnings model used by MISO TOs in this proceeding. Trial Staff contends that, in fact, as support for his contention that financial literature supports the use of multiple methods to estimate the cost of equity, Dr. Morin cites Professor Eugene Brigham who identifies the DCF, CAPM, and Risk Premium models as the "[t]hree methods [that] typically are used . . . when . . . estimating a company's cost of equity"[457] and does not identify the Expected Earnings model. Trial Staff argues that, therefore, Dr. Morin's own source of information on the use of multiple ROE methodologies excludes the Expected Earnings approach as one of the methods typically used. LPSC and CAPs' expert Mr. Solomon also point to Dr. Morin's discussion of the comparable earnings approach which states, among other things, that "Accounting rates of return are not opportunity costs in the economic sense . . . More simply, the Comparable Earnings standard ignores capital markets."[458] MISO TOs counter that these parties "cherry-pick" Dr. Morin's treatise. MISO TOs assert that they disregard Dr. Morin's explanation of the benefits of the approach, which states that "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value . . . is highly meaningful."[459] Trial Staff and LPSC also cite to recent testimony by Dr. Morin in other proceedings that they allege supports excluding the Expected Earnings model. In particular, LPSC cites the following testimony of Dr. Morin in an Oklahoma Corporation Commission proceeding:[460]

> Q. Do you agree with Mr. Parcell's Comparable Earnings Analysis?
>
> A. *Although I myself do not rely on this accounting-based method*, I agree with Mr. Parcell's Comparable Earnings results.[461]

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[457] Trial Staff Initial Br. (I), Keyton Aff. (I) at 12-13 (citing Morin at 430); Trial Staff Initial Br. (II), Keyton Aff. (II) at 11 (citing same).

[458] LPSC Initial Br. at 17 (citing Morin at 393); CAPs Initial Br. (I), Ex. JCI-100 at 31 (citing same); CAPs Initial Br. (II), Ex. JCI-200 at 30 (citing same).

[459] MISO TOs Reply Br. (I) at 42-43 and App. 2, McKenzie Reply Aff. (I) at 69; MISO TOs Reply Br. (II) at 42-43 and App. 2, McKenzie Reply Aff. (II) at 69.

[460] *Okla. Gas and Elec. Co.*, Cause No. PUD201700496 (Okla. Corp. Comm'n).

[461] *Okla. Gas and Elec. Co.*, Cause No. PUD201700496 (Okla. Corp. Comm'n), Reb. Test. of Roger A. Morin at 33 (May 29, 2018).

Trial Staff cites testimony by Dr. Morin in a Commission proceeding in which he identified the methods available to determine cost of equity and did not include the Expected Earnings model.[462]

219. The evidence in the record regarding Dr. Morin's views on the Expected Earnings model, if anything, indicates that the Expected Earnings model is inappropriate in this context. As LPSC and CAPs note, Dr. Morin's *New Regulatory Finance* states that "[a]ccounting rates of return are not opportunity costs in the economic sense" and that the Expected Earnings model's historical-looking analog, the comparable earnings standard, "ignores capital markets." The fact that the accounting-based Expected Earnings approach does not represent opportunity costs and ignores capital markets undermines its ability to estimate "the return to the equity owner [that is] commensurate with returns on investments in other enterprises" because returns on investments depend on what price an investor must pay for the investment in the capital markets. In addition, the fact that Dr. Morin has testified that he does not use the accounting-based comparable earnings method and that the Expected Earnings model is not one of the "methods available to measure the cost of equity" further indicates that the Expected Earnings model is not appropriate to use to estimate cost of equity. MISO TOs' citation to Dr. Morin's statement that "rate of return on book value . . . is highly meaningful" is not sufficient to convince us that the Expected Earnings model is appropriate. The quoted language does not indicate that Dr. Morin believes that rate of return on book value "is highly meaningful" for purposes of determining cost of equity. Rate of return on book value could be highly meaningful for other purposes—e.g., for determining revenues because rate of return is applied to the book value of a utility's rate base—but this does not mean that it is necessarily highly meaningful for determining cost of equity. In light of the other academic literature and testimony evidence in the record, we find that this evidence does not justify using the Expected Earnings model in our ROE analysis.

220. Trial Staff also notes that Professor Brigham has stated that the Expected Earnings model's historical-looking analog, the comparable earnings approach, "has now been thoroughly discredited . . . and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-

[462] San Diego Gas & Electric Company, Prepared Direct Testimony of Dr. Roger A. Morin on behalf of San Diego Gas & Electric Company, Docket No. ER19-221-000, at 16-17 (filed Oct. 30, 2018) ("There are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in financial literature.").

premium method, and (iii) the CAPM."[463] LPSC cites another article that states that

> Investments in equity shares are made by the purchase of shares at market prices. Therefore, the fairness of the rate of return to the investor must be judged from the investor's point of view in the market place and not on the basis of book value.[464]

LPSC also cites to studies that it claims demonstrate that accounting rates of return like those produced by the Expected Earnings model are unreliable as a measure of economic returns. In particular, LPSC cites a paper that concludes that "the accounting rate of return—after tax as well as before tax—is a misleading measure of the economic rate of return."[465] LPSC further cites an article which observed that, over a 15-year period "We see that the annual rates of return based on book value have fluctuated very little, while the annual rates of return to the investor in the market have fluctuated quite wildly."[466]

221. We find that this evidence does not support using the Expected Earnings model in our ROE analysis. Trial Staff's cited evidence indicates that the similar accounting-based comparable earnings approach has been "thoroughly discredited" and replaced by market-oriented rather than accounting-oriented approaches. As discussed above, this is logical given that the return an investor requires and the return an investor receives are dependent on the market price that investor must pay for the investment, not the accounting book value of the investment. Similarly, the evidence cited by the LPSC demonstrates that accounting rates of return do not reflect the economic rate of return actually received by an investor. *Hope* requires us to ensure that the return to a utility's

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[463] Trial Staff Initial Br. (I) at 7 and Keyton Aff. (I) at 13-14 (citing Eugene F. Brigham, Dilip K. Shome & Steve R. Vinson, *Cost of Capital Estimation, The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management Spring 1985, at 33); Trial Staff Initial Br. (II) at 7 and Keyton Aff. (II) at 12 (citing same).

[464] LPSC Initial Br. at 18 (citing Alexander A. Robichek, *Regulation and Modern Finance Theory*, 33 Journal of Finance 693, 701 (1978)).

[465] LPSC Initial Br. at 22 (citing Franklin M. Fisher & John J. McGowan, *On the Misuse of Accounting Rates of Return to Infer Monopoly Profits*, 73 American Economic Review 82, 89 (1983)).

[466] *Id.* at 23 (citing Alexander A. Robichek, *Regulation and Modern Finance Theory*, 33 Journal of Finance 693, 701-702 (1978)).

equity owner is "commensurate with returns on investments in other enterprises having corresponding risks" but if an accounting-based model like the Expected Earnings model does not take into account the market price of investments in other enterprises and thus the economic return rate of return on those investments, then it cannot accurately estimate the "returns on investments in other enterprises" that we must analyze in order to assess a utility's ROE. Accordingly, we find that this evidence does not support using the Expected Earnings model in our ROE analysis.

222. As support for using the Expected Earnings model, MISO TOs' witness, Mr. McKenzie, cites to a 1991 NARUC survey in which it reported that 19 regulatory jurisdictions cited the comparable earnings approach as a primary method favored in determining the allowed ROE.[467] He also notes that the Virginia State Corporation Commission is required by statute to consider the earned returns on book value of electric utilities in its region when making ROE determinations.[468] This evidence is insufficient to persuade us that using the Expected Earnings model is appropriate. As an initial matter, the over 30-year old survey that MISO TOs cite addresses the use of the comparable earnings method, which is based on historical book returns and is not the Expected Earnings model that is at issue here.[469] Similarly, the cited Virginia statute relates to past returns on book value, not expected returns like those considered in the Expected Earnings model. Moreover, this is evidence of what regulators consider in making ROE determinations, not necessarily what investors consider in making investment decisions and determining what return they will receive on their investment, which necessarily involves a consideration of the market price that must be paid to make the investment. Accordingly, this evidence does not persuade us that return on book value can be used to estimate the "return to the equity owner" that we must ensure is "commensurate with returns on investments in other enterprises having corresponding risks" under *Hope*.

223. In addition, the application of the Expected Earnings model in the electric utility cost-of-service context could produce illogical results that render use of the model sub-optimal. The simple math of the equation is that the higher the ratio of earnings to book value a given company features, the higher the resulting return from the model. Much of

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[467] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 67-68 (citing Nat'l Ass'n of Regulatory Util. Comm'rs, *Utility Regulatory Policy in the U.S. and Canada, 1995-1996* (Dec. 1996)); MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 67-68 (citing same).

[468] *See* Va. Code Ann. § 56-585.1.A.2.a (2019).

[469] *See* Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 4-5; Trial Staff Reply Br. (II), Keyton Reply Aff. (II) at 4-5.

the earnings from regulated utilities comes from the return earned in their cost-of-service rates. In such rates, the higher the percentage of equity in the capital structure, the higher the overall return, and thus earnings, would be, because the cost of equity is higher than the cost of debt. Consequently, holding all else equal, if a utility features an equity-rich capital structure, the Expected Earnings model would produce a higher return than if it featured a less equity-rich capital structure. This is illogical because the latter utility would be riskier than the former given its higher amount of leverage. Thus, the model would imply that less risky companies merit higher returns, when investors would require a lower return from those companies.

224. In addition, book value in the expected earnings calculation, if it follows general accounting conventions, would take the initial value of assets and subtract depreciation (and include any subsequent adjustments like write-downs). This leads to higher returns from the model for utilities that feature older, more-depreciated, assets than newer ones. Again, all else being equal, utilities with more depreciated assets are generally of lower risk, because they have recovered more of their invested capital, and thus they would generally merit a lower return, than utilities with newer assets.

225. Finally, we note that the MISO TOs' Expected Earnings model, unlike the other market-based models, is based solely on projections and features data from a single *Value Line* analyst. Thus the data, even if reviewed by others at *Value Line*, is much less robust and more subject to error than the data underlying the CAPM and DCF models, most of which is historic, easily verifiable, and comes from more than the projections of a single analyst.

226. We recognize that, in Opinion No. 551, the Commission reversed the Presiding Judge's rejection of MISO TOs' Expected Earnings analysis. However, in Opinion No. 551, the Commission only found that "MISO TOs' expected earnings analysis is sufficiently reliable to be used as corroborative evidence that the midpoint of the zone of reasonableness produced by the mechanical application of the DCF methodology does not result in a return that satisfies the requirements of *Hope* and *Bluefield*."[470] The Commission stated that "The expected earnings analysis, like the other alternative methodologies accepted herein, is merely used as corroborative evidence . . . which at most can corroborate the Commission's decision to place an ROE above the midpoint of the zone of reasonableness."[471] Here, the question before the Commission is whether to adopt the proposal in the Briefing Order to directly use the results of the Expected Earnings model in the ROE estimate calculations that are the foundation of our ROE analysis. We find that stronger evidence is required to support a decision to include the Expected Earnings model as a direct input in our ROE methodology than is required to

[470] Opinion No. 551, 156 FERC ¶ 61,234 at P 239.

[471] *Id.* P 233.

merely use it as corroborative evidence for placing an ROE within the zone of reasonableness. We have directed the parties in these proceedings to address the Briefing Order's proposal to use the Expected Earnings model as a direct input in our ROE methodology and, in light of the evidence that they have provided, we find that there is not sufficient support to use the Expected Earnings model as a direct input in our ROE methodology. The question in this proceeding regarding the Expected Earnings model differs from the question that was considered in Opinion No. 551. Accordingly, our decision to exclude the Expected Earnings model from our ROE methodology here is not inconsistent with our determination in Opinion No. 551.

227. Some parties argue that, if the Expected Earnings model is used, the Commission should implement certain modifications to the model.[472] MISO TOs argue against implementing these modifications.[473] We find that these arguments are moot and that it is unnecessary to address them because we will not use the Expected Earnings model as part of our ROE methodology. For the same reason, we find it unnecessary to address the arguments that oppose using the Expected Earnings model on other grounds, such as the LPSC's *Daubert* arguments,[474] and the applicable counterarguments.

228. Because we find that it is not appropriate to use the Expected Earnings model in our ROE methodology, we grant the requests for the rehearing of Opinion No. 551 in the First Complaint proceeding and the exceptions to the Initial Decision in the Second Complaint proceeding that ask the Commission to exclude the Expected Earnings model from its ROE determinations, to the extent those requests for rehearing and exceptions are based on our reasoning discussed above for excluding the Expected Earnings model.

VII. CAPM

A. Background

229. Investors use CAPM analysis as a measure of the cost of equity relative to risk.[475] The CAPM methodology is based on the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific

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[472] *See, e.g.*, CAPs Initial Br. (I) at 44-46; CAPs Initial Br. (II) at 44-46; Trial Staff Initial Br. (I) at 18-19 and ; Trial Staff Initial Br. (II) at 18; RPGI Initial Br. (I), Ex. RPG-17 at 25-26; RPGI Initial Br. (II), Ex. RPG-38 at 26; LPSC Initial Br. at 29.

[473] *See, e.g.*, MISO TOs Reply Br. (I) at 47-51; MISO TOs Reply Br. (II) at 47-51.

[474] *See, e.g.*, LPSC Initial Br. at 15-20.

[475] Opinion No. 551, 156 FERC ¶ 61,234 at P 138.

security. Specifically, the CAPM methodology estimates the cost of equity by taking the "risk-free rate" and adding to it the "market-risk premium" multiplied by "beta."[476] The risk-free rate is represented by a proxy, typically the yield on 30-year U.S. Treasury bonds.[477] Betas, which are published by several commercial sources, measure a specific stock's risk relative to the market. The market risk premium is calculated by subtracting the risk-free rate from the expected return. The expected return can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals. A CAPM analysis is backward-looking if the expected return is determined based on historical, realized returns. A CAPM analysis is forward-looking if the expected return is based on a DCF analysis of a large segment of the market. Thus, in a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF analysis.[478]

230. In the First Complaint proceeding, MISO TOs submitted a forward-looking CAPM analysis of each company in the proxy group. MISO TOs used the 2.7 percent 30-year U.S. Treasury average historical bond yield for November 2014 to April 2015 for the risk-free rate,[479] beta values for each proxy company reported by *Value Line*, and a market risk premium based on a one-step DCF study of all dividend-paying companies in the S&P 500.[480] In that DCF study, MISO TOs added the weighted average dividend of those companies (2.4 percent) to the average of the weighted average growth rates projected for the companies by IBES and *Value Line* (8.9 percent). MISO TOs did not include a long-term growth projection in its DCF study of the dividend-paying companies in the S&P 500. MISO TOs' DCF study resulted in a uniform cost of equity for the dividend-paying companies in the S&P 500 of 11.3 percent. The MISO TOs then subtracted from that figure the 2.7 percent risk-free rate to obtain a risk premium of 8.6 percent. The MISO TOs multiplied this risk premium by the beta listed for each proxy company by *Value Line* and added the risk-free rate to that product. This CAPM analysis

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[476] *Id.* (citing Morin at 150).

[477] *Id.* P 138.

[478] *See id.* PP 150, 155.

[479] Ex. MTO-30 at 1. MISO TOs also performed a CAPM study using the average projected 30-year U.S. Treasury bond yield for 2016-2020. *Id.* at 2. However, the Presiding Judge rejected that study, finding that projected bond yields are speculative and therefore less reliable for a CAPM study than current Treasury bond yields. Initial Decision (I), 153 FERC ¶ 63,027 at P 309. MISO TOs did not except to this ruling.

[480] Ex. MTO-1 at 97-98.

produces an unadjusted ROE range of 7.86 percent to 10.87 percent for the proxy group, with a midpoint value of 9.37 percent.[481]

231. However, after adjusting for the effect of each proxy company's size, MISO TOs' CAPM analysis produced an ROE range of 7.50 percent to 12.61 percent, with a midpoint value of 10.06 percent.[482] MISO TOs' witness, Dr. Avera, explained that the "size adjustment reflects the fact that differences in investors' required rate of return that are related to firm size are not fully captured by beta."[483] Dr. Avera based his size adjustments on data contained in a table published in Morningstar Inc.'s (Morningstar) "2015 Ibbotson SBBI Market Report." The table adjusts each proxy company's cost of equity based on its size, reducing the unadjusted cost of equity of larger companies, while increasing those of smaller companies.[484]

232. In Opinion No. 551, the Commission affirmed the Presiding Judge's acceptance of MISO TOs' CAPM analysis "to be used as corroborative evidence" in determining where to place MISO TOs' ROE in the DCF zone of reasonableness.[485] The Commission rejected challenges to MISO TOs' calculation of the market risk premium and use of a size adjustment. In their requests for rehearing of Opinion No. 551, CAPs and OMS contend that the Commission erred in approving MISO TOs' CAPM analysis, taking issue with how MISO TOs implemented their CAPM analysis.[486]

233. In the Second Complaint proceeding, MISO TOs submitted a CAPM study using the identical methodology as the CAPM study they presented in the First Complaint proceeding.[487] After the size adjustment, that study produced a zone of reasonableness of

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[481] Opinion No. 551, 156 FERC ¶ 61,234 at P 139.

[482] *Id.* P 140; Initial Decision (I), 153 FERC ¶ 63,027 at P 264 (citing Ex. MTO-30 at 1).

[483] Opinion No. 551, 156 FERC ¶ 61,234 at P 140 (citing Ex. MTO-1 at 98).

[484] *Id.* (citing Ex. MTO-30 at 1).

[485] *Id.* PP 165-172.

[486] *See* CAPs Rehearing Request at 28-29, 49-58; OMS Rehearing Request at 5, 26-34.

[487] *See* Ex. MTO-36.

7.97 percent to 12.12 percent with a midpoint of 10.05 percent.[488] The Presiding Judge rejected most challenges to that study.[489] However, the Presiding Judge found that MISO TOs erred in using both IBES and *Value Line* short-term growth projections in its DCF analysis of the dividend paying companies in the S&P 500, and should have only used IBES growth projections.[490] The Presiding Judge found that revising MISO TOs' CAPM study to use only the IBES growth projections reduced the midpoint from 10.05 percent to 9.67 percent, and he approved MISO TOs' CAPM study with that modification.[491]

234. Although MISO TOs' excepted to the Presiding Judge's rejection of their proposal to use only the *Value Line* short-term growth projections in their two-step DCF analysis of the proxy group,[492] they did not except to the Presiding Judge's rejection of the use of *Value Line* short-term growth projections as part of the DCF analysis of the dividend-paying companies in the S&P 500 for purposes of their CAPM study. However, CAPs, OMS and JCA, and RPGI filed exceptions to the Presiding Judge's approval of MISO TOs' CAPM study, as modified, objecting to the use of a one-step DCF analysis of the dividend-paying companies in the S&P 500 and the size adjustment.[493]

235. In the Briefing Order, the Commission proposed to give the CAPM model equal weight, along with the DCF model and Expected Earnings model, in establishing a composite zone of reasonableness to be used under the first prong of section 206 to determine whether the existing ROE has become unjust and unreasonable.[494] It also proposed to give the CAPM model equal weight, along with the DCF, Expected Earnings, and Risk Premium models, in determining a new just and reasonable ROE, when the existing ROE has been shown to be unjust and unreasonable under the second prong of section 206.[495] The Commission also recognized that the fact it was no longer

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[488] Initial Decision (II), 155 FERC ¶ 63,030 at P 405.

[489] *See id.* PP 392-474.

[490] *Id*. P 412.

[491] *Id.* PP 409, 412, 474.

[492] *See* MISO TOs Br. on Exceptions at 12-30.

[493] *See* CAPs Br. on Exceptions at 69-79; OMS and JCA Br. on Exceptions at 5, 48; RPGI Br. on Exceptions at 57-64.

[494] *See* Briefing Order, 165 FERC ¶ 61,118 at PP 13, 17.

[495] *Id.* P 18.

proposing to use the alternative methodologies only to corroborate setting the ROE above the midpoint of the DCF zone of reasonableness raises the issue of whether there should be any adjustments to how we implement the alternative methodologies, including the CAPM model.[496]

B. Use of CAPM Generally

236. Parties generally do not oppose use of the CAPM in the Commission's ROE methodology, with most parties generally agreeing that proper application of the CAPM model can produce reliable ROE results and that investors use the CAPM model.[497] As noted above, some parties argue that the Commission should continue to exclusively rely the DCF model but those parties do not oppose the use of the CAPM model if the Commission does move to a multiple-model ROE methodology.[498] However, the parties disagree on the proper application of the CAPM model. The record evidence demonstrates that this model is widely used by investors.[499] Academic literature similarly indicates that investors rely on the CAPM.[500] Moreover, the CAPM is directly relevant to

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[496] *Id*. P 41.

[497] *See, e.g.*, CAPs Initial Br. (I) at 28 ("The CAPM analysis, as corrected by Mr. Gorman, produces reliable results.") and Ex. JC-100 at 11; CAPs Initial Br. (II) at 27 and Ex. JC-200 at 10; Trial Staff Initial Br. (I), Keyton Aff. (I) at 11 ("the DCF, CAPM, and Risk Premium methods which are widely used by investors."); Trial Staff Initial Br. (II), Keyton Aff. (II) at 10; LPSC Initial Br. at 8; MISO TOs Initial Br. (I) at 4; MISO TOs Initial Br. (II) at 6. Alliant and OMS neither explicitly support, nor oppose, the use of the CAPM.

[498] *See, e.g.*, RPGI Initial Br. (I) at 11, 25-29; RPGI Initial Br. (II) at 14-15, 29-33; CAPs Initial Br. (I) at 12-25, 27-28; CAPs Initial Br. (II) at 11-25, 27-28.

[499] *See, e.g.*, Trial Staff Initial Br. (I), Keyton Aff. (I) at 11 ("the DCF, CAPM, and Risk Premium methods which are widely used by investors."); Trial Staff Reply Br. (I) at 5 ("'There are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in financial literature.'" (quoting San Diego Gas & Electric Company, Prepared Direct Testimony of Dr. Roger A. Morin on behalf of San Diego Gas & Electric Company, Docket No. ER19-221-000, at 16-17 (filed Oct. 30, 2018))); MISO TOs Initial Br. (II) at 6 (explaining that the CAPM is "widely relied upon by investors.").

[500] *See, e.g.*, Jonathan B. Berk and Jules H. van Binsbergen, *Assessing asset pricing models using revealed preference*, 119(1) Journal of Financial Economics 1, 2 (2016) ("We find that the CAPM is the closest model to the model that investors use to

the Commission's task in this context of assessing what rate of return on equity investors require to invest in a utility.[501] John Graham and Campbell Harvey have explained that "the CAPM is by far the most popular method of estimating the cost of equity capital."[502] Accordingly, we adopt the CAPM as one of the models that the Commission will use in its methodology for assessing whether an ROE is just and reasonable and determining just and reasonable ROEs when existing ROEs have been shown to be unjust and unreasonable. Below we address the parties' arguments regarding how the CAPM model should be implemented.

C. Calculation of Market Risk Premium

1. Risk-Free Rate

237. As noted above, the market risk premium in the CAPM model is calculated by subtracting the risk-free rate from the expected market return. Parties generally support the use of 30-year U.S. Treasury average historical bond yield over a six-month period as the risk-free rate.[503] RPGI proposes using the 20-year U.S. Treasury average historical

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make their capital allocation decisions . . . investors appear to be using the CAPM to make their investment decisions."); Brad M. Barber, et al., *Which Factors Matter to Investors? Evidence from Mutual Fund Flows*, 29(10) The Review of Financial Studies 2600, 2639 (2016) ("[W]hen we ran a horse race between six asset-pricing models, the CAPM is able to best explain variation in flows across mutual funds."); *id.* at 2624 ("[T]he CAPM does the best job of predicting fund-flow relations.").

[501] *See, e.g.*, Michael C. Ehrhardt and Eugene F. Brigham, *Financial Management: Theory and Practice* 253 (13th ed. 2011) ("[T]he basic CAPM is still the most widely used method for thinking about required rates of return on stocks.").

[502] John R. Graham and Campbell R. Harvey, *The theory and practice of corporate finance: Evidence from the field*, 60(2) Journal of Financial Economics 187, 201 (2001).

[503] *See, e.g.*, CAPs Initial Br. (I) at 34 ("The components of a properly implemented forward-looking CAPM methodology include: (1) the use of the actual 30-year U.S. Treasury bond yield during the six-month study period for the risk-free rate") and Ex. JC-100 at 11, 26; Trial Staff Initial Br. (I) at 11 ("Mr. Keyton also accepts the use of the risk-free rate as the yield on the 30-year U.S. Treasury bonds."); LPSC Initial Br. at 38; MISO TOs Reply Br. (I), App. 2 at 28 ("The CAPM applications presented in Mr. Gorman's and Mr. Keyton's affidavits all use an average yield on 30-year U.S. Treasury bonds for the risk-free rate and rely on *Value Line* beta values. I agree with these aspects of their analyses.").

yield over a six-month period as the risk-free rate, but only supports this proposal with a footnote stating that "Use of 20-year Treasury bonds is appropriate as risk-free rate since this is the maturity of bonds used in Morningstar study as measurement of long-term government bonds."[504] We find that the evidence supporting the use of the 30-year U.S. Treasury average historical bond yield over a six-month period as the risk-free rate outweighs the evidence supporting the use of the 20-year U.S. Treasury yield. RPGI is the only party to propose using the 20-year U.S. Treasury yield and the other evidence and precedent provides greater support for using the 30-year U.S. Treasury yield.[505] Accordingly, we adopt use of the 30-year U.S. Treasury average historical bond yield over a six-month period as the risk-free rate.

238. CAPs argue that the six-month period for purposes of determining the risk-free rate should be the same time period as used to produce the DCF study in the applicable proceeding.[506] Other parties do not disagree with this argument and generally use the same time period as used to produce the DCF study or a time period as close as possible to that time period.[507] Accordingly, we adopt the use of the 30-year U.S. Treasury average historical bond yield over a six-month period corresponding as closely as possible to the six-month financial study period as the risk-free rate.

2. Expected Market Return

a. Background

239. As described above, in the CAPM model, the market risk premium is calculated by subtracting the risk-free rate from the expected market return. The expected market return can be estimated either using a backward-looking approach based upon realized

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[504] RPGI Initial Br. (I), Ex. RPG-17 at 11 & n.29; RPGI Initial Br. (II), Ex. RPG 38 at 11 & n.29.

[505] *See, e.g.*, Morin at 151-152 ("[T]he yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods."); Opinion No. 531-B, 150 FERC ¶ 61,165 at P 114 ("30-year U.S. Treasury bond yields are a generally accepted proxy for the risk-free rate in a CAPM analysis, and are also considered superior to short- and intermediate-term bonds for this purpose.").

[506] *See* CAPs Initial Br. (1), Ex. JC-100 at 26; CAPS Initial Br. (II), Ex. ICG-200 at 25.

[507] *See, e.g.*, MISO TOs Initial Br. (I) at 24-25; Trial Staff Initial Br. (I), Keyton Aff. (I) at 8; RPGI Initial Br. (I), Ex. RPG-38 at 11.

market returns during a historical period, a forward-looking approach applying the DCF model to a representative market index, such as the S&P 500, or a survey of academics and investment professionals.[508]

240. In Order No. 551, the Commission affirmed the Presiding Judge's findings that the MISO TOs' witness, Dr. Avera, properly calculated a forward-looking expected market return, using a one-step DCF analysis of the dividend-paying companies in the S&P 500. The Commission found that Dr. Avera's use of an average of IBES and *Value Line* short-term growth projections as his short-term growth projection and his decision to not include a long term growth projection were acceptable. The Commission stated that, while it has found that *Value Line*'s growth rate estimates are not acceptable for purposes of the two-step DCF model, the Commission has nevertheless found that *Value Line* is a valid source of general financial data.[509] In his CAPM analysis, Dr. Avera uses the *Value Line* data in conjunction with IBES data and both are averaged over a 400-company data set. The Commission held that

> this use of growth rate data is fundamentally different from how growth rate data is used in the DCF model, because it is intended to provide a less precise cost of equity estimate than the DCF model. Although we require more precision from our DCF model—as the primary financial model that we use . . . to determine public utility ROEs—that same degree of precision is less essential in the CAPM analysis because that analysis is but one of multiple pieces of evidence corroborating the results of our DCF analysis.[510]

Furthermore, the Commission stated that no party demonstrated that reliance on IBES growth rate estimates alone would produce a materially different CAPM result.

241. The Commission also found that a long-term growth component is not required in the DCF study when developing a market risk premium for a CAPM analysis.[511] The Commission stated that "the rationale for requiring a two-step DCF methodology that incorporates a long-term growth rate input when conducting a DCF study on a specific group of public utilities does not necessarily apply when conducting a DCF study of the

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[508] Morin at 155-162.

[509] Opinion No. 551, 156 FERC ¶ 61,234 at P 169.

[510] *Id*.

[511] *Id.* P 170.

companies in the S&P 500."[512] Further, over protests from parties that MISO TOs did not use the S&P 500, the Commission explained that MISO TOs selected every dividend-paying stock included in the S&P 500, totaling approximately 400 companies, and that each company selected had a high market capitalization at that time. The Commission determined that, consistent with Opinion No. 531-B, the resulting DCF study of the approximately 400 dividend-paying stocks need not include a two-step DCF methodology that incorporates a long-term growth rate input.[513]

242. In the Second Complaint proceeding, the Presiding Judge in his initial decision, issued before Opinion No. 551, held that MISO TOs erred in using both IBES and *Value Line* short-term growth projections in the DCF analysis of the dividend paying companies in the S&P 500. The Presiding Judge found that, because the Commission does not permit use of *Value Line* growth projections in its regular DCF analyses of public utility and pipeline proxy groups, those growth projections also should not be used as part of the DCF analysis of the dividend paying companies in the S&P 500 for purposes of a CAPM analysis.[514] However, the Presiding Judge did, consistent with Opinion Nos. 531 and 551, find that Dr. Avera properly used a one-step DCF analysis for this purpose.

b. MISO TOs

243. MISO TOs support the Commission's holdings in Opinion No. 551 concerning the DCF analysis of the dividend paying members of the S&P 500 for purposes of determining the CAPM market risk premium. They argue that the Commission properly approved use of an average of *Value Line* and IBES short-term growth projections. MISO TOs state that in Opinion No. 551 the Commission found that "*Value Line* is a valid source of general financial data" and that the "use of growth rate data [in the CAPM] is fundamentally different from how growth rate data is used in our DCF model."[515] MISO TOs argue that Trial Staff does not confront this finding, but instead raises generalized arguments that do not invalidate the reliability of *Value Line*'s growth rate estimates. MISO TOs assert that the Commission has not ruled out consideration of *Value Line* in any and all contexts. MISO TOs add that Trial Staff's claim that IBES growth rates are updated more frequently than *Value Line*'s lacks any empirical support, and in any event, there is no evidence that the frequency of updates has any bearing on

[512] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113).

[513] *Id.*

[514] *Id*. P 412.

[515] MISO TOs Reply Br. (I) at 27 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 169); MISO TOs Reply Br. (II) at 27.

investor reliance on either IBES or *Value Line*.[516] MISO TOs conclude that the Commission should continue to allow the use of *Value Line* data in CAPM analyses.

244. MISO TOs also support the Commission's determination in Order No. 551 to use a single stage DCF model to develop the market risk premium for the CAPM analysis, noting that the Commission has already twice rejected CAPs and other parties' arguments that the two-step DCF is required.[517] According to MISO TOs, it is appropriate to use a single stage DCF to evaluate the S&P 500 Index because the "growth rates used in the MISO TOs' CAPM studies are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index *as a whole*."[518] Mr. McKenzie asserts that concerns about the sustainability of such growth rates for a single firm miss the point because the growth rate represents the weighted average of investors' expectations for the dividend paying firms in the S&P 500 Index, not a growth rate for a single firm that is assumed to be constant in perpetuity. MISO TOs' witness Mr. McKenzie states that the S&P 500 includes a broad sample of corporations from widely varied and distinct industries. He states that growth expectations for some firms fall below expected trends in GDP, while projections for other firms are more optimistic. He also points out that the composition of the S&P 500 is not static. As a result, formerly successful firms are supplanted by new firms with potential for high growth, for example Sears is supplanted by Amazon or Blockbuster by Netflix.[519]

245. Mr. McKenzie also asserts that academic research supports the use of a single-step DCF model when performing a DCF analysis of the S&P 500.[520] For example, Mr. McKenzie points out that in *Estimating Shareholder Risk Premia*, Harris and Marston estimate the market-required rate of return by performing a DCF analysis of the

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[516] MISO TOs Reply Br. (I) at 28-29; MISO TOs Reply Br. (II) at 28-29.

[517] MISO TOs Reply Br. (I) at 23; MISO TOs Reply Br. (II) at 23.

[518] MISO TOs Reply Br. (I) at 24 and App. 2 at 26 (emphasis added by MISO TOs); MISO TOs Reply Br. (II) at 24 and App. 2 at 26.

[519] MISO TOs Reply Br. (I), App. 2 at 20 and 26; MISO TOs Reply Br. (II), App. 2 at 20 and 26.

[520] MISO TOs Reply Br. (I), App. 2 at 23-25 (citing Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Fin. Mgmt., Spring 1986; Robert S. Harris & Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Fin. Mgmt., Summer 1992; and Felicia Marston & Robert S. Harris, *Risk and Return: A Revisit Using Expected Returns*, Fin. Rev., Feb. 1993); MISO TOs Reply Br. (II), App. 2 at 23-25 (citing same).

dividend paying companies in the S&P 500. Consistent with the MISO TOs' CAPM approach, Harris and Marston state that "[t]he mean value of the individual analysts' forecasts of five-year growth rates in [earnings per share] will be used as a proxy for g in the DCF model."[521] In addition, Mr. McKenzie points out that Harris and Marston state that "[t]he five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts."[522] Moreover, Harris and Marston emphasize that their use of a one-step DCF analysis to determine the market-required rate of return "is applied to portfolios of stocks [i.e., the S&P 500], rather than to individual securities, since future growth patterns may be expected to have drastic changes for some specific securities."[523]

246. MISO TOs state that the DCF analysis used to determine an input into the CAPM need not mimic the DCF model used to yield ROE estimates for individual public utilities. "It is a feature . . . that the CAPM and the Commission's DCF rely on different approaches to estimate investors' expected return on equity."[524] They state that reliance on the one-step DCF is consistent with the Briefing Order's approach reducing the risk of misidentifying the ROE through the use of multiple models. Finally, MISO TOs argue that CAPs have not provided any reason for the Commission to revisit its findings on this matter.[525]

c. CAPs

247. In their request for rehearing of Opinion No. 551, brief on exceptions to the Initial Decision in the Second Complaint proceeding, and briefs in response to the Briefing Order, CAPs assert that the Commission's two-step DCF methodology is required to accurately calculate the market risk premium of the CAPM,[526] and assert the MISO TOs'

[521] MISO TOs Reply Br. (I), App. 2 at 23-24; MISO TOs Reply Br. (II), App. 2 at 23-24.

[522] MISO TOs Reply Br. (I), App. 2 at 24; MISO TOs Reply Br. (II), App. 2 at 24.

[523] MISO TOs Reply Br. (I), App. 2 at 26; MISO TOs Reply Br. (II), App. 2 at 26.

[524] MISO TOs Reply Br. (I) at 24; MISO TOs Reply Br. (II) at 24.

[525] MISO TOs Reply Br. (I) at 24; MISO TOs Reply Br. (II) at 24.

[526] CAPs Initial Br (I) at 30-31; CAPs Initial Br. (II) at 30-31.

CAPM study improperly used the one-step DCF.[527] CAPs assert that including only short-term growth rates in this DCF calculation implies that such growth will continue in perpetuity, and assumes that a company can grow faster than the economy for an indefinite period of time.[528] They also comment that such an assumption is both unrealistic and inconsistent with the Commission's prior determinations.[529] CAPs assert that failure to include a second-stage growth rate in the CAPM portfolio DCF calculation runs counter to economic logic.[530]

248. In their request for rehearing of Opinion No. 551, CAPs assert that the record in the First Complaint proceeding shows that the investment community expects corporate earnings growth to track GDP growth.[531] For example, they cite Pacific Investment Management Company (PIMCO's) "Asset Allocation Secular Outlook 2015," in which PIMCO projects a 10-year return on U.S. equities of 4.5 percent.[532] They point out that this is well below the 11.3 percent market return estimated by the MISO TOs' one-step DCF analysis of the dividend paying members of the S&P 500 in the MISO TOs' CAPM study in the First Complaint proceeding. CAPs also observe that PIMCO states that its estimate of "[e]xpected earnings growth is based on per capita real GDP growth estimates."[533] CAPs also state that the PIMCO report calculates a forward-looking equity risk premium of 3.9 percent by comparing the projected 10 year return of the S&P 500 to

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[527] CAPs Initial Br. (I) at 30 (citing Ex. JC-100 at 11-13); CAPs Initial Br. (II) at 30-31 (citing Ex. ICG-200 at 11-13); CAPs Rehearing Request at 49-55; CAPs Br. on Exceptions at 74-78.

[528] CAPs Initial Br. (I) at 30; CAPs Initial Br. (II) at 30.

[529] CAPs Initial Br. (I) at 30 (citing *Generic Determination of Rate of Return in Common Equity for Pub. Utils*., Order No. 420, FERC Stat. & Regs. at 31,344 & n.39 (finding that inflated equity cost estimates result when analysists estimate risk premiums using "DCF estimates of the investors' required rate of return" on "common stock," because "the use of analysts' short-term forecasts overstate[s] investors' long term growth expectations."); CAPs Initial Br. (II) at 30 (citing same).

[530] CAPs Initial Br. (I) at 31 (citing Ex. JC-100 at 14); CAPs Initial Br. (II) at 31 (citing Ex. ICG-200 at 14).

[531] CAPs Rehearing Request at 54.

[532] *Id*. (citing Ex. S-11 at 6).

[533] *Id*. (citing Ex. S-11 at 7).

inflation protected 10-year treasury bonds. CAPs state that this is less than half the 8.6 percent equity risk premium calculated by the MISO TOs.[534]

249. In addition to the PIMCO report, CAPs state that the American Appraisal Risk Premium Quarterly calculated a forward-looking risk premium of 6.0 percent, and Duff & Phelps calculated a forward-looking risk premium of 5.0 percent.[535] Also, according to CAPs, *Value Line* estimated "that the required equity premium above the yield on ten-year bonds in order to induce investment in corporate equity was about 5.5 percent."[536]

250. CAPs assert that these facts demonstrate that the 11.3 percent market return calculated by MISO TOs using the one-step DCF method, without any long-term GDP growth projection, is "way out of line with forward-looking (and historical) investment-community sources."[537] CAPs conclude that a two-step DCF method must be used to calculate the market return. They state that using a two-step DCF analysis of the dividend paying members of the S&P 500 in the First Complaint proceeding would lower the equity risk premium from 8.6 percent to 7.1 percent and lower the midpoint of the CAPM zone of reasonableness to 8.89 percent.[538] CAPs make similar arguments, relying on similar evidence, in their Brief on Exceptions to the Initial Decision in the Second Complaint proceeding.[539]

251. CAPs challenge MISO TOs' reliance upon three academic papers published between 1986 and 1993 that applied a one-stage DCF in constructing their CAPM models.[540] CAPs explain that these studies estimated that the risk premium of a diversified equity portfolio over long-term U.S. bonds averaged well under seven percent,

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[534] *Id*. (citing Ex. S-11 at 10).

[535] *Id*. (citing Ex. JCI-4 at 46-47).

[536] *Id.* (citing Ex. S-1 at 15).

[537] *Id*. at 54-55.

[538] *Id*. at 55.

[539] CAPs Br. on Exceptions at 75-77.

[540] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Fin. Mgmt., Spring 1986; Robert S. Harris & Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Fin. Mgmt., Summer 1992; and Felicia Marston and Robert S. Harris, *Risk and Return: A Revisit Using Expected Returns*, Fin. Rev., Feb. 1993.

less than the 8.6 percent and 8.2 percent that Mr. McKenzie applied in his CAPMs for the First Complaint and Second Complaint study periods. CAPs also assert that these studies are not relevant here because they tested whether the cost of equity varied over time and across company risks, not the absolute value of the cost of equity.[541] CAPs posit that the authors did not use a two-stage DCF methodology because long-term growth "was tangential to what they sought to measure."[542]

252. CAPs disagree with Mr. McKenzie's argument that investors can expect long-term dividend growth that exceeds the growth rate of the U.S. economy because the composition of the S&P 500 Index is not static and firms with high growth potential replace firms with low growth potential.[543] CAPs argue that regardless of index composition, the equity market as a whole cannot sustainably grow faster than the economy as a whole. Finally, CAPs assert that the S&P 500 Index does not grow through the substitution of firms, but instead when there is a substitution of firms, the index value is held constant.[544]

253. CAPs contest Mr. McKenzie's argument that the portfolio return must exceed the 9.29 percent that Opinion No. 551 found insufficient for electric utilities.[545] CAPs argue that because Opinion No. 551 is under reconsideration by the Commission, it should not be relied upon here. Further, CAPs argue that the decision in Opinion No. 551 to place the base ROE above the DCF midpoint was based on the fact that CAPM results, if premised on an unsustainable equity portfolio return, pointed above the DCF midpoint. CAPs assert that relying upon that decision to require an equity portfolio return above the DCF midpoint would be untenably circular. Also, they argue that the appropriate comparison would be between the average (or median) composite earnings growth rate used in the utility DCF and the composite earnings growth rate used in the CAPM's portfolio DCF. CAPs explain that the earnings growth rate for the CAPM equity portfolio is substantially higher than that of the utility proxies. CAPs' witness, Mr. Gorman recommended a modification of the DCF-based CAPM portfolio return, with an average composite earnings growth rate of 7.4 percent. CAPs argue that the

[541] CAPs Reply Br. (I) at 17-18; CAPs Reply Br. (II) at 33-34.

[542] CAPs Reply Br. (I) at 18; CAPs Reply Br. (II) at 34.

[543] CAPs Reply Br. (I) at 19 (citing MISO TOs, McKenzie Reply Aff., Docket No. EL11-66, at 27-28 (filed Mar. 8, 2019)); CAPs Reply Br. (I) at 35-36 (citing same).

[544] CAPs Reply Br. (I) at 19; CAPs Reply Br. (II) at 35-36.

[545] CAPs Reply Br. (I) at 20 (citing MISO TOs, McKenzie Reply Aff., Docket No. EL11-66, at 31 (filed Mar. 8, 2019)); CAPs Reply Br. (II) at 36 (citing same).

earnings growth rate for the CAPM equity portfolio is substantially higher than that of the utility proxies, as expected given the utility proxies' low risk. And, they argue that this difference contradicts the MISO TOs' claim that the growth rate obtained by applying a second-stage growth constraint to portfolio earnings is too low when compared to utility stock financial data.[546]

254. CAPs disagree with Mr. McKenzie's assertion that other regulators rely on a one-stage DCF to find CAPM portfolio returns.[547] They comment that Mr. McKenzie's assertion relied upon testimony that was filed 18 years ago in a state commission proceeding. According to CAPs, in the *Coakley* Briefing Order proceeding, a survey of electric transmission ROE regulation in Australia, Canada, the United Kingdom and Europe showed that when regulators apply CAPM models, they use equity market returns that are typically about 4.75 percent to 6.0 percent above the risk-free governmental security yield.[548]

255. In their request for rehearing of Opinion No. 551, CAPs state that they are not seeking rehearing of the Commission's acceptance of MISO TOs' use of an average of IBES and *Value Line* growth projections as the short-term growth projection in their DCF analysis of the dividend paying members of the S&P 500 in the First Complaint proceeding. CAPs agree with Opinion No. 551's finding that the record in the First Complaint proceeding is insufficient to show that removal of the *Value Line* growth projection would materially affect the results of the MISO TOs' CAPM analysis. However, CAPs state that they support the Presiding Judge's decision in the Second Complaint proceeding to eliminate the *Value Line* growth projection and use only IBES as the short-term growth projection.[549]

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[546] CAPs Reply Br. (I) at 20-21; CAPs Reply Br. (II) at 36-37.

[547] CAPs Reply Br. at 21 (citing MISO TOs, McKenzie Reply Aff., Docket No. EL11-66, at 28-29 (filed Mar. 8, 2019)).

[548] CAPS Reply Br. (I) at 21 (citing Docket No. EL11-66, Ex. CAP-600 at 37-46); CAPS Reply Br. (II) at 37 (citing same).

[549] CAPs Rehearing Request at 55-56 n.193.

d. Trial Staff

256. Trial Staff argues that the DCF component of CAPM should be calculated following the Commission's two-step DCF methodology.[550] Trial Staff asserts that use of the one-step DCF model implies that a company can grow faster than the economy for an indefinite period of time.[551] Trial Staff also comments that such an assumption is both unrealistic and inconsistent with the Commission's prior determinations.[552]

257. In its briefs in both the First and Second Complaint proceedings, Trial Staff also argues that only IBES growth rates should be used as the short-term growth projection in the DCF model employed in a CAPM analysis.[553] Trial Staff states that *Value Line* does not represent consensus earnings growth estimates, but rather the estimate of a single analyst.[554] Trial Staff alleges that IBES growth rates are updated more frequently. Trial Staff's witness, Mr. Keyton, included in the workpapers attached to his affidavit in the First Complaint proceeding the IBES growth projections for the dividend-paying members of the S&P 500 necessary for calculating a short-term growth projection using only IBES growth projections.[555]

258. Trial Staff proposes to remove companies from the CAPM whose short-term IBES growth rates or composite growth rates are less than or equal to zero, and those greater than or equal to 20 percent, as supported by Dr. Morin.[556] Trial Staff argues that the Commission has previously found that zero or negative growth rates are either

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[550] Trial Staff Initial Br. (I) at 13-14; Trial Staff Initial Br. (I) at 12-13 Trial Staff Reply Br. (I) at 10-11; Trial Staff Reply Br. (II) at 11.

[551] Trial Staff Initial Br. (I) at 13-14; Trial Staff Initial Br. (II) at 12-13.

[552] Trial Staff Initial Br. (I) at 14 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 36 n.63 and Morin at 308); Trial Staff Initial Br. (II) at 13 (citing same).

[553] Trial Staff Initial Br. (I) at 11-12; Trial Staff Initial Br. (II) at 11.

[554] Trial Staff Initial Br. (I) at 12. Trial Staff Initial Br. (II) at 11.

[555] Trial Staff Initial Br. (I), Keyton Aff., (I) Attachment B at 8-14; Trial Staff Initial Br. (I), Keyton Aff. (II), Attachment B at 7-12.

[556] Trial Staff Initial Br. (I) at 16-18; Trial Staff Initial Br. (II) at 16-17.

economically illogical or unsustainable.[557] Trial Staff states that, similarly, the Commission has also screened for high-end short-term growth rates.[558] Trial Staff also reasons that employing growth rate screens in both the DCF and the CAPM provides for consistency among methods.[559]

e. Other Parties

259. LPSC argues that the Commission should adopt the two-step DCF to determine the CAPM's market risk premium. They argue that MISO TOs' one-step approach "inflated the yield compared to what would be developed using the two-step approach."[560] LPSC continues that it is inconsistent to match the short-term DCF forecast with the yield on long-term bonds.[561] RPGI argues that the 8.6 percent market risk premium component of the CAPM adopted in the Briefing Order exceeds long-term risk premiums by approximately 6 percent.[562]

f. Commission Determination

260. We continue to find reasonable the MISO TOs' proposal to estimate the CAPM expected market return using a forward-looking approach, based on applying the DCF model to the dividend paying members of the S&P 500. Using a DCF analysis of the dividend-paying members of the S&P 500 is a well-recognized method of estimating the expected market return for purposes of the CAPM model.[563] The DCF analysis must be limited to the dividend-paying members of the S&P 500, rather than using all companies in the S&P 500, because a DCF analysis can only be performed on companies that pay dividends.

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[557] Trial Staff Initial Br. (I) at 17 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 38-39); Trial Staff Initial Br. (II) at 16 (citing same).

[558] Trial Staff Initial Br. (I) at 17 (citing *ISO New England, Inc., et al.*, 109 FERC ¶ 61,147, at P 205 (2004) (indicating Commission removal of a company from the proxy group whose short-term growth rate was 13.3 percent)); Trial Staff Initial Br. (II) at 1617 (citing same).

[559] Trial Staff Initial Br. (I) at 17; Trial Staff Initial Br. (II) at 17.

[560] LPSC Initial Br. at 37.

[561] *Id.* at 38.

[562] RPGI Initial Br. (I) at 27; RPGI Initial Br. (II) at 31.

[563] Morin at 160.

261. No participant opposes the use of a DCF analysis of the dividend-paying members of the S&P 500 to estimate the expected market return. However, CAPS, LPSC, and Trial Staff raise several issues with respect to the growth projection used by MISO TOs in their CAPM analyses in both complaint proceedings. These issues include: (1) the use of the one-step DCF model without any long-term growth projection based on GDP; (2) whether S&P 500 companies included in the DCF analysis should be screened for unrealistic growth projections; and (3) the use of an average of IBES and *Value Line* growth projections as the short-term growth projection. For the reasons discussed below, we are not persuaded by CAPs and Trial Staff's arguments in support of a two-step DCF analysis to calculate the CAPM expected market return. However, we agree with CAPs that the *Value Line* growth projections should not be included in the DCF analysis.

262. Financial research supports using a one-step DCF analysis of the dividend paying members of the S&P 500 when determining a forward looking expected market return as part of the CAPM model. For example, in *Estimating Shareholder Risk Premia*, Harris and Marston present estimates of shareholder required rates of return and risk premiums using forward-looking analysts' growth forecasts. They state that "a 'market' required rate of return is calculated using each dividend paying stock in the S&P 500 for which data is available."[564] In describing this process, the authors state, "This expectational approach employs the [DCF model] in which a consensus measure of financial analysts' forecasts . . . of earnings is used as a proxy for investor expectations."[565] They continue that "[t]he mean value of individual analysts' forecasts of five-year growth rate in [earnings per share (EPS)] will be used as a proxy for *g* in the DCF model," and state that the "five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts."[566] A second study cited by MISO TOs cautions against "the introduction of *ad hoc* assumptions about future growth" beyond the five-year time-frame used by IBES.[567] That study also emphasizes, "[i]mportantly, however, the approach is applied to portfolios of stocks rather than to individual securities, since future growth patterns may be expected to have drastic changes for some specific securities."[568] Thus, these studies support Opinion No. 531-B's holding that a long-term growth projection is not needed when performing a

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[564] *Estimating Shareholder Risk Premia* at 3.

[565] *Id.* at 2.

[566] *Id.*

[567] *Required Rates of Return* at 61.

[568] *Id*.

DCF analysis of a portfolio of stocks, despite the fact such a growth projection is needed when doing a DCF analysis of a single utility.[569] We note that the third study also relies solely upon analysts' five-year IBES growth forecasts.[570]

263. As the Commission found in Opinion No. 531-B, we continue to find that the rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not apply when conducting a DCF study of the companies in the S&P 500.[571] The Commission's rationale for incorporating a long-term growth rate estimate in DCF analyses for public utilities is that it is often unrealistic and unsustainable for high short-term growth rates to continue in perpetuity for a particular utility or group of utilities.[572] The purpose of the DCF analysis in the CAPM model differs from the purpose of using the DCF analysis to directly estimate a utility's cost of equity. The purpose of the DCF analysis in the CAPM model is to determine the "required return on the overall market" that will be used to determine the market risk premium—which is based on the difference between the "required return on the overall market" and the risk-free rate.[573]

264. As described above, the required return on the overall market is determined by conducting a DCF study of "a representative market index, such as the Standard & Poor's 500 Index."[574] We find that there are at least two reasons why it is not necessary to include a long-term growth projection based on GDP in a DCF analysis of the dividend paying companies in the S&P 500. First, the S&P 500 is regularly updated to ensure, among other things, that it only includes companies with high market capitalization[575] and that it remain representative of the industries in the economy of the United States. Although the value of the S&P 500 index is held constant when one company is replaced

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[569] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113.

[570] Ex. EMC-0224 at 3-4.

[571] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113.

[572] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 36 n.63.

[573] *See id.* P 113.

[574] Morin at 159.

[575] Currently, in order to be included in the S&P 500, a company must have a market capitalization of at least $8.2 billion, calculated by multiplying outstanding shares of stock by stock price.

by another as CAPs state,[576] the updating of the companies in the index has the general effect of substituting companies with declining stock values and market capitalization with companies with growing stock values and market capitalization. As Mr. McKenzie testified for the MISO TOs, "As a result formerly successful firms are supplanted by new firms with potential for high growth."[577] CAPs contest this reasoning on the ground that, although the companies in the S&P 500 are updated, the MISO TOs performed a DCF analysis of a specific group of about 400 companies, and there is no reason to expect that a group of stocks "will enjoy long-term growth at short-term rates without being affected by changes in the economy as a whole."[578] This argument misses the point. Although the MISO TOs' applied their DCF analysis to the specific companies who happened to be the dividend paying members of the S&P 500 at that point in time, the purpose of the analysis was to determine a required return on the overall market as represented by an investment in the S&P 500, which is regularly updated. Thus, it is reasonable for the inputs used in the DCF analysis, including the growth projections, to be selected based on the assumption that the subject companies will be updated in the manner described above.

265. Second, we find that, because the dividend paying members of the S&P 500 constitute a large portfolio of stocks, they include companies at all stages of growth. Some are relatively young companies with new products that have not yet fully penetrated the markets and thus are likely to have quite high IBES growth rates. However, other companies are mature companies with limited growth potential which are likely to have quite low IBES growth rates. The inclusion of the IBES growth rates of such mature companies in the overall average IBES growth rate of all the dividend paying members of the S&P 500 performs the same role as the inclusion of the long-term GDP growth rate in the DCF analysis of a single utility: it reflects the fact that companies cannot maintain indefinitely the high growth rates of their early years. Thus, using the IBES growth rates of all dividend paying S&P 500 companies, without using a long-term GDP growth projection can reasonably reflect investors' consensus expectations about the S&P 500 Index as a whole.

266. In summary, while it may be unreasonable to expect an individual company to sustain high short-term growth rates in perpetuity, the same cannot be said for a broad representative market index that is regularly updated to include new companies. Put differently, a portfolio of companies behaves differently than an individual company. Accordingly, the rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific utility or group of utilities for purposes of directly estimating cost of equity does not apply to the DCF analysis of a broad

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[576] CAPs Reply Br. (I) at 19.

[577] MISO TOs Reply Br. (I), App. 2; McKenzie Reply Aff. (I) at 26.

[578] CAPs Rehearing Request at 51.

representative market index with a wide variety of companies that is regularly updated to include new companies for purposes of determining the required return to the overall market.

267. We also accept Trial Staff's proposal to screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20 percent. Such screening is consistent with the elimination of outliers elsewhere in our ROE methodology. Such high or low growth rates are highly unsustainable and non-representative of the growth rates of the electric utilities in the proxy groups. For instance, in the Second Complaint proceeding, Helmerich and Payne featured an IBES growth rate of negative 42 percent while Cabot Oil and Gas featured an IBES growth rate of 48.1 percent.[579] Neither growth rate is sustainable for the intermediate, much less long, term and should thus be eliminated from the group of S&P 500 companies examined.

268. Evidence indicates that the use of this growth rate screen is appropriate in the CAPM analysis. For example, in *Principles of Corporate Finance*, Richard A. Brealey and Stewart C. Myers explain that "No firm can continue growing at 20 percent per year forever, except possibly under extreme inflationary conditions."[580] Dr. Morin also separately states that growth rates less than or equal to zero and greater than or equal to 20 percent should be removed from an analysis.[581] In addition, in conducting a DCF analysis of the dividend-paying S&P 500 members to estimate *ex ante* expected returns in the CAPM analysis, Harris, et al. screened out companies "if the standard deviation around the mean [analyst] forecast exceeds 20%."[582] While this screen differs from the one Trial Staff has proposed in this proceeding, it nonetheless indicates that it is appropriate to screen out companies when conducting a DCF analysis of the dividend paying S&P 500 members in the CAPM analysis. The CAPM growth rate screen that is in record evidence before us is the screen proposed by Trial Staff and there is sufficient support to indicate that it will exclude companies with growth rates that are unsustainable. Accordingly, we find that S&P 500 companies with growth rates that are negative or in excess of 20 percent should be excluded from the CAPM analysis because their growth rates are not representative of sustainable growth rates.

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[579] Trial Staff Reply Br. (I) at App. C.

[580] Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance* 68 (7th ed. 2003).

[581] Trial Staff Initial Br. (I); Keyton Aff. (I) at 33 (citing Morin at 165).

[582] Robert S. Harris et al., *Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice between Global and Domestic CAPM*, Fin. Mgmt., Autumn 2003, at 5.

269. CAPs assert that the Harris and Marston articles cited by the MISO TOs do not support use of the one-step DCF model to determine the market risk premium in these two proceedings. CAPs point out that those studies estimated that the risk premium of a diversified equity portfolio over long-term U.S. bonds averaged well under seven percent,[583] less than the 8.6 percent and 8.2 percent market risk premiums that the MISO TOs used in their CAPM analyses for the First Complaint and Second Complaint study periods. Based upon our holdings in this order, we calculate market risk premiums in the First and Second Complaint proceedings of 9.12 percent and 8.85 percent respectively. The fact that the absolute market risk premiums calculated in the Harris and Marston articles for varying periods between 1982 and 1991 are lower than those we calculate based on financial information for the first and second halves of 2015 does not undercut our reliance on the Harris and Marston articles. In *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Harris and Marston found that the "market risk premium varies over time. In particular, the equity market premium over government bonds is higher in low interest rate environments."[584] Government bond interest rates were significantly lower during 2015 than during the 1982 to 1991 period.[585] Therefore, the fact that we have found higher market risk premiums of 9.12 percent and 8.85 percent during the first and second halves of 2015, rather than the less than 7.0 percent risk premiums Harris and Marston found during 1982 to 1991 is consistent with the Harris and Marston articles. Indeed, Dr. Morin cites a subsequent 2003 article by Harris, Marston, Mishra, and O'Brien[586] in which they estimate the market risk premium rising to just above 9 percent in 1998, using the same methodology as in the earlier Harris and Marston articles cited by the MISO TOs.

270. CAPs also assert that the Harris and Marston articles are not relevant here because they tested whether the cost of equity varied over time and across company risks, not the

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[583] The first article estimated 1982 average annual risk premiums of 6.16 percent. The second article estimated 1982-1991 average annual risk premiums of 6.47 percent, and the third article estimated 1982-1987 average annual premiums of 5.66 percent.

[584] Robert S. Harris & Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Fin. Mgmt., Summer 1992, at 1.

[585] *See, e.g.* St. Louis Federal Reserve, Treasury Constant Maturity Rate Data, https://fred.stlouisfed.org/categories/115.

[586] Morin at 160 (citing Robert S. Harris et al., *Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice between Global and Domestic CAPM*, Fin. Mgmt., Autumn 2003, at 51-66).

absolute value of the cost of equity.[587] CAPs posit that the authors did not use a two-stage DCF because long-term growth "was tangential to what they sought to measure."[588] However, as discussed above, in *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Harris expressly supported using the one-step DCF model when performing a DCF analysis of a portfolio of stocks, such as the S&P 500, as opposed to individual securities. The Harris and Marston articles discuss how the costs of equity calculated by their studies varied over time and across company risks for the purpose of confirming the accuracy of their analyses using a one-step DCF study of the dividend paying members of the S&P 500, not as a separate inquiry.

271. We are not persuaded by Trial Staff's arguments that Dr. Morin supports the two-step DCF analysis for a market risk premium used in a CAPM. In particular, Trial Staff argues that Dr. Morin supports the underlying theory of incorporating a long-term growth estimate in the DCF methodology, citing his statement that "eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy."[589] However, Dr. Morin made this statement in the context of discussing the DCF analysis of a single company or utility, not the market risk premium used in a CAPM. As discussed above, in discussing the application of the DCF model to a representative market index for purposes of estimating a prospective market risk premium for the CAPM, Dr. Morin cited the studies by Marris and Marston and the study by Harris, Marston, Mishra, and O'Brien discussed above.[590]

272. Finally, in their request for rehearing of Opinion No. 551, CAPs contend that the 8.6 percent market risk premium calculated by MISO TOs in the First Complaint proceeding using a one-step DCF analysis to estimate the expected market return is substantially higher than forward-looking market risk premiums calculated by other financial analysts during the same time period. They cite a PIMCO report calculating a forward-looking equity risk premium of 3.9 percent calculated by comparing the projected 10-year return of the S&P 500 to inflation protected 10-year treasury bonds. They also state that the American Appraisal Risk Premium Quarterly calculated a forward-looking risk premium of 6.0 percent, Duff & Phelps calculated a forward-looking risk premium of 5.0 percent, and *Value Line* estimated that the required equity

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[587] CAPs Reply Br. (I) at 17-18; CAPs Reply Br. (II) at 33-34.

[588] CAPs Reply Br. (I) at 18; CAPs Reply Br. (II) at 34.

[589] Morin at 308.

[590] *Id.* at 159-164.

premium above the yield on ten-year bonds in order to induce investment in corporate equity was about 5.5 percent.

273. There are a variety of views as to the reasonable market risk premium to include in a CAPM study and what method to use to determine that premium, as is clear from Dr. Morin's summary of academic studies of both historical and prospective market risk premiums. Dr. Morin concludes that "Faced with this myriad, and often conflicting, evidence on the magnitude of the risk premium, a regulator might very well be confused about the correct market risk premium."[591] Although the risk premiums we approve in this order exceed those of certain other analyses, we find that their determination is analytically sound and supported by the evidence in this proceeding. We find, on balance, that the MISO TOs' use of a one-step DCF analysis of the dividend paying members of the S&P 500, in conjunction with Trial Staff's outlier test, to determine the expected market return is reasonable.

274. We now turn to the issue of what short-term growth projection sources to use in the one-step DCF analysis. For the reasons discussed below, we find that only the IBES three to five year consensus growth projections should be used. Thus, we find that MISO TOs erred in averaging the IBES growth projections with single analyst *Value Line* growth projections. This determination is consistent with our determination above to utilize IBES data for the short-term growth projection in the two-step DCF model. In that determination, we held that the record suggests that IBES provides more stable and robust data than *Value Line*, because, among other reasons, the IBES growth projections are consensus projections generally based on projections from a number of independent analysts and brokerage and investment firms, whereas the *Value Line* growth projections are by a single analyst.[592] Moreover, the Commission has rejected proposals to average IBES short-term growth projections with *Value Line* growth estimates, finding that *Value Line* projections are "projections from a single source" and their use would "dilute the industry consensus reflected in the IBES data."[593]

275. In addition, the Marston and Harris articles cited above in support of using a one-step DCF analysis of the dividend paying members of the S&P 500 as part of determining the market risk premium endorse the use of IBES projections as the single growth projection in that analysis. For example, Harris and Marston concluded in *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts* that the use of IBES data

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[591] *Id.* at 163.

[592] *See, e.g.*, *supra* PP 125-127.

[593] *Nw. Pipeline Corp.*, 87 FERC at 62,058-59; *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 234.

"offers a straightforward and powerful aid to establishing required rates of return either for corporate investment decisions or in the regulatory arena." [594]

276. As MISO TOs point out, Opinion No. 551 accepted their proposal to average IBES and *Value Line* growth projections for purposes of the DCF analysis of the dividend paying members of the S&P 500 as part of implementing the CAPM model. However, in doing so, the Commission explained, "Although we require more precision from our DCF model—as the primary financial model that we use, and have used for decades, to determine public utility ROEs—that same degree of precision is less essential in the CAPM analysis because that analysis is but one of multiple pieces of evidence corroborating the results of our DCF analysis."[595] In this order, by contrast, we find that it is appropriate to give equal weight to the DCF and CAPM models in setting just and reasonable ROEs. Accordingly, the CAPM model must be implemented with the same degree of precision as the DCF model. Therefore, having found that use of the IBES growth projections is preferable to the *Value Line* growth projections, we require the sole use of IBES growth projections for the DCF component of the CAPM analysis.

D. Betas and Size Premium

1. CAPs

277. In their initial briefs, CAPs argue that Dr. Avera's CAPM approach improperly includes a size premium adjustment to the base CAPM ROE range. CAPs contend that Dr. Avera's application of the size premium adjustment produces an inflated and unreliable CAPM result due to the use of mismatched betas. As explained below, CAPs assert that the betas used in Dr. Avera's base CAPM are different from, and incompatible with, the betas in the size premium adjustment. Thus, CAPs argue that the adjusted CAPM results accurately reflect neither a security's investment risk nor the market-required return on that investment risk level. CAPs assert that, as Mr. Gorman testifies, the CAPM model produces the most reliable results when it does not include a size premium adjustment.[596]

278. CAPs note that in the base CAPM, Dr. Avera relied on *Value Line*'s adjusted betas. CAPs state that *Value Line* measures a "raw" beta based on a regression of the monthly returns of the individual companies, relative to the New York Stock Exchange

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[594] Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Fin. Mgmt., Summer 1992, at 6.

[595] Opinion No. 551, 156 FERC ¶ 61,234 at P 169.

[596] CAPs Initial Br. (I) 31-32; CAPs Initial Br. (II) 31-32.

(NYSE) average, over a five-year period. CAPs note that *Value Line* then adjusts the raw beta for the long-term tendency of beta to converge on the market beta of one over long periods of time. CAPs state that *Value Line*'s adjusted betas represent a raw beta estimate given two-thirds weight and the market beta of one given one-third weight.[597] CAPs also note that *Value Line* publishes its adjusted betas, not its raw betas.[598]

279. CAPs further state Dr. Avera's size premium adjustment relies on Duff & Phelps unadjusted or "raw" betas. CAPs note that Duff & Phelps' raw betas are produced by a regression study of the monthly returns on the stock index that are in excess of a 30-day U.S. Treasury yield over the period 1926 through the most recent period. CAPs state that, unlike *Value Line*, Duff & Phelps does not adjust raw betas for the long-term tendency of betas to converge on the market beta of one over time, and thus, the *Value Line* and Duff & Phelps betas are not measured in the same manner and are incompatible with each other. Additionally, CAPs argue that Duff & Phelps explicitly caution against the use of mismatched betas. CAPs assert that when these two betas are combined, as Dr. Avera has proposed, they do not accurately measure the risk or required return for a security and in fact, inflate the CAPM return estimate.[599]

280. CAPs argue that Mr. Gorman corrects Dr. Avera's CAPM to incorporate raw betas in both the base CAPM analysis and the size adjustment, which makes it evident that the use of mismatched betas inflates the CAPM results. CAPs contend that Mr. Gorman's corrected version of Dr. Avera's base CAPM produces a midpoint value of 8.40 percent and, after applying the size adjustment, a midpoint value of 9.09 percent. Further, CAPs assert that, when a consistent beta methodology is used to measure both the base CAPM and size adjustment, the resulting midpoint of 9.09 percent is reasonably comparable to a base CAPM return using a *Value Line* adjusted beta without a size premium. CAPs argue that the use of unrelated betas involves an apples-and-oranges measurement of risk and return, and therefore the CAPM should not include a size adjustment.[600]

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[597] CAPs Initial Br. (I) at 32 (citing Ex. JC-100 at 17); CAPs Initial Br. (II) at 32 (citing Ex. ICG-200 at 17).

[598] CAPs Initial Br. (I) at 32 (citing Ex. JC-100 at 18-19); CAPs Initial Br. (II) at 32 (citing Ex. ICG-200 at 17).

[599] CAPs Initial Br. (I) at 32-33 (citing Ex. JC-100 at 18-19); CAPs Initial Br. (II) at 32-33 (citing Ex. ICG-200 at 18-19).

[600] CAPs Initial Br. (I) at 33-34; CAPs Initial Br. (II) at 33-34.

2. Trial Staff

281. Trial Staff witness, Mr. Keyton, supports omitting the size premium adjustment. Trial Staff argues the three most important reasons the size premium adjustment should be removed are: (1) it is a questionable method with conflicting support among academics; (2) the data on which the Commission relied to support a size premium adjustment in Opinion No. 551 contradicts the Commission's goal to use forward-looking methods for developing the cost of equity; and (3) Mr. Keyton's regression analysis determined there is no meaningful relationship between forward-looking DCF results and current market capitalizations.[601] Mr. Keyton also notes that several scholars disagree over the use of a size premium adjustment in numerous studies.[602] Trial Staff also argues that in Opinion No. 551, the size premium adjustment was based on historical (rather than forward-looking) data that shows smaller market capitalization companies earn higher returns than larger market capitalization companies.[603]

282. In reply briefs, Trial Staff agrees with CAPs and LPSC that the size premium adjustment is unsupported and may amount to double counting. Trial Staff agrees with LPSC that there is no empirical evidence suggesting the need for a size premium adjustment.[604]

3. Other Parties

283. LPSC also criticizes the MISO TOs' use of the raw beta for determining the size premium adjustment while using the *Value Line* adjusted beta for the CAPM calculation. LPSC also argues that the stock index used to derive beta should be the same as the index used to determine the required return on equity.[605] LPSC states that in Opinion No. 551, the Commission accepted a CAPM analysis that forecasted equity returns and compared them with current long-term bond yields. LPSC argues that MISO TOs' witness Dr. Avera, however, matched a short-term DCF equity return with long-term Treasury bond yields, contrary to the guidance in *New Regulatory Finance*. LPSC argues MISO TOs applied a beta developed by comparing utility stock volatility with that of the New York Stock Exchange, but then applied that beta to dividend-paying firms in the

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[601] Trial Staff Initial Br. (I) at 14; Trial Staff Initial Br. (II) at 13-14.

[602] Trial Staff Initial Br. (I) at 15; Trial Staff Initial Br. (II) at 14.

[603] Trial Staff Initial Br. (I) at 15; Trial Staff Initial Br. (II) at 14-15.

[604] Trial Staff Reply Br. (I) at 10; Trial Staff Reply Br. (II) at 10.

[605] LPSC Initial Br. at 8.

S&P 500, which created a mismatch that conflicts with advice in *New Regulatory Finance*.[606]

284. LPSC argues that the MISO TOs' method incorrectly applied a size premium adjustment to increase the return on equity, on the theory that beta does not fully account for risk differences resulting from the size of firms. LPSC argues that no empirical evidence suggesting the need for a size premium adjustment for utilities was cited and it appears that none exists. LPSC argues the empirical evidence in the record, capitalization amounts and DCF results for the proxy group, shows that size is completely unrelated to the required return on equity.[607] LPSC also points to a regression analysis between company size and the DCF-calculated ROEs to argue that the size premium adjustment is inappropriate, citing the lack of apparent relationship between required return and company size.[608]

285. RPGI opposes the incorporation of a size premium adjustment in CAPM calculations and argues it has been shown through empirical studies to be invalid as applied to utilities. RPGI further notes that Mr. Parcell demonstrated in a study comparing the size of a utility with its risk factors, that there is no significant difference and there is no discernible pattern of increase among the risk indicators of publicly-traded electric utilities of different sizes.[609]

4. MISO TOs

286. In reply briefs, MISO TOs argue there is no rational basis for Mr. Gorman's argument that it is inappropriate to use *Value Line*'s adjusted betas in conjunction with size premium adjustments from Duff & Phelps and that his attempt to interject raw betas into the process simply biases his results downward.[610] MISO TOs contend that Duff & Phelps neither recommends a specific source for beta, nor suggests that adjusted betas are incompatible with their size premia adjustments. MISO TOs argue that Duff & Phelps simply observed that, because there can be differences in the methodologies used by alternative reporting services, it is preferable to use the same, consistent source of betas

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[606] *Id.* at 36.

[607] *Id.*

[608] *Id.* at 40-42.

[609] RPGI Initial Br. (I) at 28-29 (citing Parcell Aff. (I) at 11); RPGI Initial Br. (II) at 32 (citing Parcell Aff. (II) at 10).

[610] MISO TOs Reply Br. (I) at 29-30; MISO TOs Reply Br. (II) at 29-30.

for all companies included in the analysis.[611] Further, MISO TOs argue that there is no inconsistency between the two betas because the beta values reported by *Value Line* are based on an ordinary least-squares analysis, as are the size premium adjustments reported by Duff & Phelps for the firm size deciles.[612]

287. MISO TOs oppose the "build-up method" presented by Mr. Gorman, which they argue is based on historical risk premiums that have been rejected by the Commission and found to be considerably downward-biased.[613] MISO TOs argue that Mr. Gorman confuses the size premium adjustment required by the CAPM with aspects of the build-up method described in a Duff & Phelps publication and that the CAPM and build-up method are not synonymous and in fact are distinct methods for estimating the cost of equity. MISO TOs contend that the industry risk adjustment Mr. Gorman uses in the context of the build-up method is in lieu of the more precise beta risk measure for each firm in the proxy group that is employed in the CAPM. MISO TOs assert that Mr. Gorman's observation that regulated utility companies' industry risk is lower than companies in other industries does not support the use of a generic industry risk adjustment, as risk differences are already reflected in the CAPM through the use of beta. Further, MISO TOs argue the Commission has already rejected Mr. Gorman's build-up method, as well as the related logical errors underlying his contentions regarding the CAPM size premium adjustment and the Commission should continue to do so.[614]

288. MISO TOs assert the Commission should continue to include a size premium adjustment when applying the CAPM. MISO TOs argue that Duff & Phelps conclude in the publication attached to Mr. Gorman's affidavit that observation of the size effect is consistent with a modification of the pure CAPM, that studies have shown the limitations of beta as a sole measure of risk, and that the size premium adjustment is an empirically

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[611] MISO TOs Reply Br. (I) at 30; MISO TOs Reply Br. (II) at 30.

[612] MISO TOs Reply Br. (I) at 30 n.56; MISO TOs Reply Br. (II) at 30 n.56.

[613] MISO TOs Reply Br (I) at 32 (citing *N.Y. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,043, at P 105, *reh'g denied*, 147 FERC ¶ 61,148 (2014), *appeal denied sub nom. Cent. Hudson Gas & Elec. Corp. v. FERC*, 783 F.3d 92 (2015)); MISO TOs Reply Br (II) at 32 (citing same).

[614] MISO TOs Reply Br. (I) at 33-34 (citing Opinion No. 551, 156 FERC ¶ 61,234 at PP 142, 166); MISO TOs Reply Br. (II) at 33-34 (citing same).

derived correction to the pure CAPM.[615]

289. MISO TOs argue Mr. Parcell and Mr. Keyton incorrectly place significant weight on a 1993 study by Annie Wong that refutes the need for a size premium adjustment when applying the CAPM to a utility. MISO TOs contend that a closer examination of this research reveals that it is largely inconclusive and inconsistent with CAPM and demonstrates no material difference between utilities and industrial firms with respect to size premiums. MISO TOs argue that her study also finds no significant relationship between beta and returns, which contradicts modern portfolio theory and the CAPM.[616]

290. MISO TOs assert that Mr. Parcell's observation that the majority of publicly traded companies are unregulated and operate in industries that are much riskier than the utility industry says nothing at all about the relevance of a size premium adjustment. MISO TOs argue that the fact that the size premia reported by Duff & Phelps was estimated on an industry-by-industry basis provides no basis to ignore the relationship in estimating the cost of equity for utilities. MISO TOs contend that Mr. Gorman concluded that a size premium adjustment for a regulated utility company should only be considered along with recognizing the low-risk nature of the regulated utility industry and that that is exactly the effect of combining *Value Line*'s beta values for the proxy companies with beta adjusted size premiums reported by Duff & Phelps.[617]

291. In response to Mr. Parcell's claims that a comparison of risk measures for utilities of different size demonstrates that there is no need for a size premium adjustment, MISO TOs argue the size premium adjustment is narrowly tailored to address an inability of beta to fully account for the impact of firm size within the CAPM, and the CAPM did not even figure into Mr. Parcell's simplistic comparison.[618]

292. In response to Mr. Keyton's claims that a regression between DCF estimates for the dividend-paying firms in the S&P 500 index and market capitalization demonstrates there is no need for a size premium adjustment, MISO TOs argue that the size premium does not relate to cost of equity estimates computed using the DCF model, which were the basis for Mr. Keyton's regression. Rather, MISO TOs assert that they are solely intended to address an inability of beta to account for the impact of firm size, and beta did

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[615] MISO TOs Reply Br. (I) at 35-36 (citing Ex. JC-101 at 3); MISO TOs Reply Br. (II) at 35-36 (citing Ex. JC-101 at 3).

[616] MISO TOs Reply Br. (I) at 36; MISO TOs Reply Br. (II) at 36.

[617] MISO TOs Reply Br. (I) at 40; MISO TOs Reply Br. (II) at 40.

[618] MISO TOs Reply Br. (I) at 40; MISO TOs Reply Br. (II) at 40.

not even figure into Mr. Keyton's regression. MISO TOs argue that Trial Staff's calculations have nothing whatsoever to do with the CAPM and say nothing about the relevance of the size premium adjustment.[619] MISO TOs assert that these observations apply equally to the LPSC's regression between DCF estimates and size. Further, MISO TOs contend that the size premium adjustment relates to beta, not the DCF model, and the fact that DCF estimates may not be correlated with market capitalization is unrelated to the size premium adjustment, as applied in the CAPM.[620]

293. MISO TOs argue that Mr. Parcell's historic premium of 6.0 percent is too low and that he incorrectly calculated the equity risk premium using the total return for Duff & Phelps' long-term government bond series. MISO TOs assert that, as a result, his historical equity risk premiums fall far below what his own source reports and Mr. Parcell's CAPM analysis is further compromised. MISO TOs argue that using only the arithmetic mean income component of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security.[621]

294. In response to LPSC's arguments that *Value Line* betas cannot be applied to firms in the S&P 500 due to a mismatch, MISO TOs contend that application of the DCF approach to the dividend-paying firms in the S&P 500 Index provides a sound proxy for investors' expected return on the market. MISO TOs assert that similarly, reference to *Value Line*'s published beta values also offer an objective proxy for an unobservable forward-looking beta and that there is no mismatch.[622]

295. MISO TOs argue that LPSC wrongly contends that the size premium adjustment is predicated on a finding that utilities are generally smaller than the companies in the S&P 500 and that size premium adjustments correspond to market capitalization across the spectrum of publicly traded firms.[623]

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[619] MISO TOs Reply Br. (I) at 41; MISO TOs Reply Br. (II) at 41.

[620] MISO TOs Reply Br. (I) at 42; MISO TOs Reply Br. (II) at 42.

[621] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 35; MISO TOs Initial Br. (II), App. 2McKenzie Aff. (II) at 35.

[622] MISO TOs Reply Br. (I) at 31; MISO TOs Reply Br. (II) at 31.

[623] MISO TOs Reply Br. (I) at 38 n.85; MISO TOs Reply Br. (II) at 38 n.85.

5. Commission Determination

296. With regard to MISO TOs' size premium adjustment, the Commission stated in Opinion No. 531-B that the use of such an adjustment was "a generally accepted approach to CAPM analyses."[624] We continue to find this to be the case.

297. CAPs argue that it is inconsistent to apply the Ibbotson size adjustment, which is derived based on raw betas, to a CAPM analysis that uses adjusted betas. We continue to find that the *Value Line* adjusted betas are reasonable for use in the CAPM. There is substantial evidence in the record that investors rely on *Value Line* betas.[625] No party objects to use of adjusted betas, which Dr. Morin supports, stating that "the regression tendency of betas to converge to 1.0 over time is very well known and discussed in the financial literature."[626] We acknowledge that there is imperfect correspondence between the size premia being developed with different betas. Nonetheless, we conclude that the size premium adjustments improve the accuracy of the CAPM results and cause it to better correspond to the costs of capital estimates employed by investors.

298. We also find that the application of size premium adjustments based on the NYSE to dividend-paying members of the S&P 500 is acceptable. The use of the NYSE for the size premium calculations enabled Ibbotson to develop a rich data set. There is no evidence that the application to a CAPM methodology using S&P 500 growth rates and dividend yields with a size premium adjustment based on NYSE data is problematic. There is no evidence that companies in the S&P 500 feature different risk premiums than those in the NYSE. Furthermore, the betas and size premia are applied to the calculated cost of equity of individual utilities in the proxy group, regardless of what stock index they may be found in.

299. We find that, though not uniform, a sufficient amount of academic literature exists to indicate that many investors rely on the size premia. Dr. Morin discusses the "size effect" finding that:

> Investment risk increases as company size diminishes, all else remaining constant. Small companies have very different returns than large ones, and on average they have been

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[624] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117.

[625] *See, e.g.*, MISO TOs Reply Br. (I), App. 2 at 31-32; Robert S. Harris & Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992 (using betas derived using *Value Line* method).

[626] Morin at 72.

> higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods.[627]

300. Dr. Morin also avers that the higher returns required by investors in small companies than the CAPM would project is well documented in the financial literature.[628] Specifically, Dr. Morin cites to work by Rolf Banz showing that from 1936 to 1975 stocks of small firms earned higher risk-adjusted abnormal returns than those of large firms.[629] Eleswarapu Reinganum found a similar dynamic, looking at the relationship between firm size and PE ratio.[630] Ibbotson Associates, now under Duff & Phelps, has long published a series quantifying this effect for various sizes of firms, pulling from data going back to 1926.

301. We also agree with the Presiding Judge that the financial literature arguing against the continued existence of the size premium or its applicability to utilities is unavailing. Specifically, we do not find persuasive the article cited by Professor Annie Wong that utilities are less risky than industrial stocks and feature betas that do not decrease with firm size.[631] Even if true, which the MISO TOs aver is not the case, the argument in favor of a size premium adjustment is that there are differences in risk and required returns between small and large companies that are not captured in the betas. Consequently, lack of substantial variance in the betas between large and small companies is not indicative that they feature differences in risk and corresponding returns that are the basis for the size premium adjustment. The subsequent endorsement of this phenomenon, by Dr. Morin, lends credence to the view that Professor Wong's conclusions are no longer state of the art. Furthermore, an article reconsiders Professor Wong's evidence and concludes that "new information… indicates that there is a small

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[627] *Id.* at 181.

[628] *Id.* at 181-183.

[629] *Id*. at 181-183 (citing Rolf Banz, *The Relationship between Return and Market Value of Common Stocks* (1981)).

[630] Eleswarapu Reinganum, *Misspecification of Capital Asset Pricing Empirical Anomalies based on Earnings Yields and Market Values*, Journal of Financial Economics, Vol. 9, 1981.

[631] Annie Wong, *Utility Stocks and the Size Effect: an Empirical Analysis* (1993).

firm effect in the utility sector."[632] A more recent article published in *Business Valuation Review* found that "none of the academic papers throughout the last three decades have qualified the [size premium] as a statistical error."[633] Finally, a 2019 National Association of Certified Valuators and Analysts publication supports the use of the size premium adjustment to the CAPM.[634] We thus find that, based on the evidence of this dynamic and that many investors consider it when evaluating companies, it is appropriate to include it in CAPM determinations.

302. We also find unconvincing Mr. Keyton and the LPSC's regression analyses demonstrating that a size premium adjustment is not appropriate for the CAPM. Mr. Keyton and LPSC's regression analyses examine the relationship between forward-looking DCF results and company size. Although DCF results do reflect the cost of capital required by investors, the DCF model is fundamentally different than the CAPM model, which relies on a distinct set of assumptions, inputs, and calculations. This diversity is part of the reason that we are including the CAPM model. By the same rationale, a regression analyses on the reasonableness of CAPM model inputs using the DCF model is unpersuasive, since that model does not consider betas at all.

303. We also find there to be insufficient reason to conclude that the utility industry is unique, as certain intervenors suggest, such that the size premium adjustment is inapplicable. The size premium adjustment is supported by a robust data set. Although the variations in the risk profiles of firms in any industry inevitably vary somewhat, we do not see sufficient evidence in the record to conclude that factors specific to the utility industry insulate smaller utilities from risks such that the CAPM betas sufficiently account for any increased risks and corresponding returns demanded by investors.

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[632] Thomas M. Zepp, *Utility stocks and the size effect—revisited*, 43 Quarterly Review of Economics and Finance 578–82 (2003).

[633] Roger A. Grabowski, *The Size Effect Continues to be Relevant When Estimating the Cost of Capital*, Business Valuation Review, Fall 2018, at 93–109 ("*Grabowski*").

[634] Roger G. Ibbotson & James P. Harrington, *Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value*, Quick Read (Jan. 30, 2019), https://quickreadbuzz.com/2019/01/30/business-valuation-grabowski-harringtonsing-a-nonbeta-adjusted-size-premium/.

VIII. Risk Premium Model

A. Background

304. The risk premium methodology, in which interest rates are also a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[635]

305. Multiple approaches have been advanced to determine the equity risk premium for a utility.[636] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[637] Another approach for the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities over some past period relative to the contemporaneous level of the long-term U.S. Treasury bond yield."[638]

306. In Opinion No. 551, the Commission found that "it is appropriate to rely on risk premium analyses as corroborative evidence during periods of anomalous capital market conditions"[639] and that "MISO TOs' risk premium analysis is sufficiently reliable to corroborate the results of the DCF analysis in this proceeding."[640] The Commission concluded that "MISO TOs' risk premium study is valid and supports awarding the MISO TOs a base ROE above the midpoint"[641] and found that "We, therefore, affirm the Presiding Judge's acceptance of the risk premium analysis to be used as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides a return that satisfies the requirements of *Hope*

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[635] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (citing Morin at 108).

[636] *See generally* Morin at 107-130.

[637] *Id.* at 110.

[638] *Id.* at 123.

[639] Opinion No. 551, 156 FERC ¶ 61,234 at P 191.

[640] *Id.* P 200.

[641] *Id.* P 191.

and *Bluefield*."[642] The Commission also made various determinations regarding specific aspects of how the Risk Premium analysis should be implemented.[643] CAPs, RPGI, and OMS requested rehearing of certain of the Commission's determinations regarding how the Risk Premium analysis was implemented.

307. In the Initial Decision in the Second Complaint proceeding, the Presiding Judge similarly found that MISO TOs' "historical risk premium analysis is valid and supports awarding the MISO TOs a Base ROE above the Midpoint."[644] The Presiding Judge also made various determinations regarding specific aspects of how the Risk Premium analysis should be implemented.[645] CAPs, OMS and JCA, and RPGI took exception to the Presiding Judge's determinations regarding how the Risk Premium analysis was implemented.

308. In the Briefing Order, for purposes of establishing a new just and reasonable ROE where the existing ROE has been shown to be unjust and unreasonable (i.e., the second prong of the FPA section 206 analysis), the Commission proposed to use the Risk Premium model, DCF model, CAPM, and Expected Earnings model to produce four separate cost of equity estimates and then average the four estimates to produce the just and reasonable ROE. For each of the DCF, CAPM, and Expected Earnings models, the Commission proposed to use the central tendency of the respective zones of reasonableness as the cost of equity estimate for average risk utilities and then average those three midpoint/median figures with the sole numerical figure produced by the Risk Premium model to determine the ROE of average risk utilities. The Commission proposed to use the midpoint/medians of the resulting lower and upper halves of the zones of reasonableness to determine ROEs for below or above average risk utilities, respectively.[646] The Commission proposed to omit the Risk Premium model from the analysis under the first prong of section 206 because it does not produce a range which can be used to determine a zone of reasonableness and instead only produces a numerical

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[642] *Id.* P 200.

[643] *Id.* PP 192-199.

[644] Initial Decision (II), 155 FERC ¶ 63,030 at P 391.

[645] *See id.* PP 353-390.

[646] *See* Briefing Order, 165 FERC ¶ 61,118 at P 18.

point. Accordingly, the Commission proposed to use the Risk Premium model output only in the second prong of the FPA section 206 analysis.[647]

B. CAPs

309. CAPs contend that the Commission erred in relying on MISO TOs' Risk Premium analysis, which CAPs argue should have been either rejected or adjusted.[648] CAPs argue that, at a minimum, the Commission should correct MISO TOs' Risk Premium analysis by refining the readings of, and dates attributed to the 81 Commission orders used as inputs in the Risk Premium analysis.[649] CAPs state that the base ROE was not at issue in many of the 81 Commission orders, including those that approved settlements. According to CAPs, by taking appropriate account of the relied upon cases, the result of MISO TOs' Risk Premium analysis would have been materially below the 10.32 percent DCF upper midpoint.[650]

310. CAPs note that nearly all of the Commission outcomes relied upon in MISO TOs' Risk Premium analysis were taken from a period when the Commission applied a one-step DCF methodology that it subsequently found to have been inappropriate. CAPs argue that such reliance unreasonably perpetuates that past error.[651] CAPs also argue that many of these cases involved incentive adders and that previously-determined base ROEs were not at issue.[652]

311. CAPs also explain that, because many of these cases involve Commission settlement and litigation, there is a meaningful disconnect between the dates of Commission orders and the period of time they reflect. CAPs argue that Opinion No. 551 failed to consider that the core of MISO TOs' Risk Premium methodology is the comparison between past findings as to the cost of equity and the contemporaneous cost of debt. CAPs point to the 12.38 percent utility cost of equity as an example. CAPs explain that the 12.38 percent base ROE was based on a study period from August 2001

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[647] *Id.* P 18 n.39.

[648] CAPs Rehearing Request at 41. CAPs state that, prior to Opinion No. 531, the Commission has repeatedly rejected risk premium analyses. *Id.* at 42.

[649] *Id.*at 28, 43.

[650] *Id.* at 41-43.

[651] *Id.* at 42 & n.153.

[652] *Id.* at 43.

through January 2002, and therefore argue that it is arbitrary and capricious for MISO TOs' Risk Premium study to compare it to bond yields in 2011, 2012, and 2013.[653]

312. CAPs state that, with its corrections to MISO TOs Risk Premium study, the resulting cost of equity drops to 9.89 percent.[654] CAPs assert that its 9.89 percent Risk Premium outcome or OMS' 9.94 percent Risk Premium outcome can serve as the representative Risk Premium result for this case.[655]

313. CAPs argue that the Commission, in Opinion No. 551, adopted a deficient Risk Premium study prepared by MISO TOs' witness, Dr. Avera. According to CAPs, MISO TOs' Risk Premium study generates inaccurate and unreliable cost of equity indicators, and should be replaced by CAPs' witness, Mr. Gorman's, Risk Premium study.[656] CAPs also contend that the Presiding Judge, in Initial Decision (II), accepted a flawed Risk Premium study prepared by MISO TOs' witness, Mr. McKenzie.[657]

314. CAPs assert that compiling past Commission findings and attempting to trend them to current market conditions is inferior to directly applying empirical techniques to current market information. CAPs claim that the data set of Commission cases used in MISO TOs' Risk Premium studies consists largely of cases where the Commission expressly declined to make such a substantive cost of capital finding.[658] CAPs assert that, therefore, the ROE in many of these cases do not reflect market costs at the time of the Commission order.[659] CAPs argue that, therefore, the fundamental assumption underlying Dr. Avera's Risk Premium analysis that was accepted in Opinion No. 551 and

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[653] *Id.* at 44-45.

[654] *Id.* at 47. CAPs propose modifications to MISO TOs' Risk Premium study regarding its use of the 12.38 base ROE, as well as its use of several other base ROEs. *Id.* at 46-48.

[655] *Id.* at 48. CAPs also state that, despite being rejected in the Initial Decision, Trial Staff witness Keyton's Risk Premium analysis was well-supported. *Id.* at 26-27.

[656] CAPs Initial Br. (I) at 35; CAPs Initial Br. (II) at 35.

[657] CAPs Initial Br. (II) at 37.

[658] CAPs Initial Br. (I) at 37 (citing Ex. JC-100 at 27-29); CAPs Initial Br. (II) at 37 (citing Ex. ICG-200 at 27, 28-29).

[659] CAPs Initial Br. (I) at 37-38; CAPs Initial Br. (II) at 37.

Mr. McKenzie's Risk Premium analysis that was accepted in Initial Decision (II), is invalid.

315. CAPs also argue that MISO TOs' Risk Premium studies rely too heavily on the inverse relationship between interest rates and risk premiums. According to CAPs, over the last five to six years, the real yield spread between utility stocks and Baa bond yields has been nearly flat.[660] CAPs assert that this shows that interest rate changes are not the sole driver of risk premium changes. Consequently, CAPs recommend applying the following parameters for risk premium determinations: (1) ROE determinations made by the Commission or state commissions at the time of the order; (2) observable market evidence of risk differential, including spreads between A-rated and Baa-rated utility bonds and long-term Treasury bonds; and (3) a comparison of utility stock yields to utility bond yields and Treasury bond yields. Applying such parameters, Mr. Gorman recommends a Risk Premium model ROE range of 8.98 to 9.12 percent in the First Complaint proceeding[661] and of 9.09 to 9.76 percent in the Second Complaint proceeding.[662]

316. CAPs also argue that the risk premium model is inherently less accurate than a well-constructed DCF or CAPM model because it relies on results of market-based methods from past cases, where the DCF and CAPM model rely on primary data. CAPs aver that the Risk Premium model tends to replicate the regulatory lag and "inertial continuation of past returns" affecting past regulatory decisions.[663]

317. In addition, CAPs contend that the MISO TOs' Risk Premium analyses rely on bond yield projections that the Commission has found to be speculative. CAPs state that MISO TOs presented no reason for use of projected bond yields other than to say that this approach is "[c]onsistent with the approach adopted in the *Coakley* Briefing Order."[664] CAPs argue that, however, the *Coakley* Briefing Order used a Risk Premium result based on the actual bond yield. CAPs point out that Initial Decision (I) in the First Complaint

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[660] CAPs Initial Br. (I) at 38 (citing Ex. JC-100 at 31, 33); CAPs Initial Br. (II) at 38 (citing Ex. ICG-200 at 33).

[661] CAPs Initial Br. (I) at 39.

[662] CAPS Initial Br. (II) at 39.

[663] CAPs Reply Br. (I) at 26; CAPs Reply Br. (II) at 46.

[664] CAPs Reply Br. (I) at 27 (citing MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 27); CAPs Reply Br. (II) at 47 (citing MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 26 n.46).

proceeding, which ROE the Briefing Order relies on for its Risk Premium figures, rejected use of a projected bond yields as "speculative,"[665] a position affirmed in Opinion No. 551.[666] CAPs contend that, in order to be internally consistent, a Risk Premium study must use projected bond yields to derive the risk premium as well as the yield to which it is added. Additionally, CAPs argue that the projected bond yields do not represent the known and measurable cost of capital and that projected bond yields have proven unreliable.

318. CAPs further argue that MISO TOs' Risk Premium approach includes ROEs from proceedings for which ROEs were not at issue. Consequently, according to CAPs, ROEs from such proceedings are not a valid basis for comparing the cost of equity and cost of debt. CAPs assert that these included two cases which the New England TOs recently admitted did not involve base ROEs.[667]

C. RPGI

319. RPGI notes that MISO TOs' Risk Premium analysis relied on ROEs authorized by the Commission from 2006 through 2014. RPGI questions why, if anomalous market conditions call into question the reliability of the DCF in this case, the same is not true for the Risk Premium analysis, which relies on DCF-produced returns after the onset of the Great Recession.[668]

320. RPGI contends that the MISO TOs have not demonstrated that the Risk Premium model addresses any of the supposed distortions in the DCF model, and thus has no demonstrated superiority over the DCF model.[669]

321. RPGI, in its Initial Brief, states that the Risk Premium methodology the Commission proposes to use is flawed due to: (1) a conceptual flaw in reasoning; (2) a misplaced reliance on research reflecting vastly different financial conditions; and

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[665] CAPs Reply Br. (I) at 27-28 (citing Initial Decision (I) at P 257); CAPs Reply Br. (II) at 47 (citing same).

[666] CAPs Reply Br. (I) at 28 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 194); CAPs Reply Br. (II) at 47 (citing same).

[667] *See* CAPs Reply Br. (I) at 31 (citing New England TOs, Initial Paper Hearing Brief, at 60 n.222, Docket No. EL11-66-001, *et al*. (filed Jan. 11, 2019)).

[668] RPGI Rehearing Request at 13-14.

[669] RPGI Reply Br. (I) at 9.

(3) flaws in the model's inputs. In order to correct these deficiencies, RPGI recommends an overhaul to the Risk Premium methodology.[670] RPGI states that its Risk Premium model, which corrects the various flaws in the proposed Risk Premium model, results in an 8.68 percent ROE.[671]

322. First, RPGI argues that the Risk Premium model incorporates the same distortions that the Commission has found to warrant a departure from full reliance on the DCF model. RPGI explains that the Risk Premium model uses the same financial data (i.e., interest rates) that the Commission found to be abnormal and unique. According to RPGI, it makes no sense to "carry forward" the same financial market conditions identified as distorting DCF inputs into an alternative model. RPGI states that, unless cured, this case-specific flaw serves as a reason for not using the Risk Premium model at all. RPGI contends that he Commission's stated rational for using other models (i.e., concerns over unusual market capital conditions) is inconsistent with relying on those same capital market conditions on a going-forward basis.[672]

323. Second, RPGI argues that the upward adjustment based on low interest rates contradicts the reasoning used to critique the DCF. RPGI explains that, according to MISO TOs witness, Ms. Lapson, artificially low interest rates have caused investors to migrate from utility bonds to utility stocks.[673] RPGI contrasts this claim with the theory underlying the adjustment included in MISO TOs' Risk Premium study, which is that lower interest rates correlate with an increase in equity risk premiums. RPGI asserts investors cannot be driven to stocks in search of higher returns and simultaneously demand a higher premium than had previously been offered. RPGI states that such investors would not migrate to stocks and take on the additional risk while simultaneously demanding an increase in the risk premium of holding stocks. RPGI contends that, if anything, MISO TOs witness Ms. Lapson's theory would suggest a narrower risk premium than under normal conditions.[674]

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[670] RPGI Initial Br. (I) at 29; RPGI Initial Br. (II) at 33.

[671] RPGI Initial Br. (I) at 37; RPGI Initial Br. (II) at 40.

[672] RPGI Initial Br. (I) at 30-31 (citing Parcell Aff. (I) at 14); RPGI Initial Br. (II) at 34 (citing Parcell Aff. (II) at 14).

[673] RPGI Initial Br. (I) at 31-32 (citing Initial Decision (I) at PP 123-136, 142-158); RPGI Initial Br. (II) at 35 (citing same).

[674] RPGI Initial Br. (I) at 32; RPGI Initial Br. (II) at 35-36.

324. Third, RPGI disputes the reliance on the research from 1985 relied upon to support the adjustment to the Risk Premium model to reflect the inverse relationship between risk premiums and interest rates.[675] RPGI explains that the authors actually found the relationship between interest rates and risk premiums to be volatile. RPGI notes that the statistical correlation between interest rates and risk premiums were actually positive over the time period from 1970 through 1979. RPGI argues that the financial conditions during the article's five-year study period from 1980 through 1984 (i.e., increasing inflationary expectations) have nothing to do with the financial conditions at issue in these proceedings. RPGI asserts that inflation is not a major investment risk, and that no meaningful conclusion can be draw from the 34-year old research.[676]

325. Fourth, RPGI argues that the MISO TOs' Risk Premium model is flawed because it measures risk premiums over a short-term period. Although RPGI concedes that Opinion No. 531 supported the use of a shortened time-period beginning with the enactment of the Energy Policy Act of 2005, RPGI notes that the Risk Premium approach was merely used as a benchmark in Opinion No. 531. RPGI states that the proposal in the Briefing Order faces a higher standard of scrutiny because it is proposed as a source of data for computing a just and reasonable return.[677]

326. Fifth, RPGI argues that the proposed Risk Premium model incorporates a number of dubious choices. RPGI states that input-related flaws include the mismatch between the time period to which the data is attributed and the utility bond yields to which they are compared. RPGI points to the instant proceedings as an example. According to RPGI, the final orders in these proceedings may be issued as many as seven or eight years after the complaints were filed and the relevant data were generated.[678] RPGI also argues that settlements should not be used in the Risk Premium Study. According to RPGI, no meaningful precedent can be drawn from a settlement because the Commission

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[675] RPGI Initial Br. (I) at 33 (citing Eugene F. Brigham et al., *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, 14 Fin. Mgmt. 33, 33-45 (1985)); RPGI Initial Br. (II) at 36.

[676] RPGI Initial Br. (I) at 34-35; RPGI Initial Br. (II) at 37-38.

[677] RPGI Initial Br. (I) at 35-36; RPGI Initial Br. (II) at 38-39.

[678] RPGI Initial Br. (I) at 36. RPGI also appears to question Midwest TDUs' sorting and combining of all ROE-related orders by calendar year. *Id.*

does not approve individual components of a settlement but rather the overall settlement.[679]

D. LPSC

327. LPSC states that risk premiums vary substantially over time, but—in theory—measuring risk premiums over a long period will even out fluctuations and reflect a normal risk premium. LPSC asserts that the nine-year period used by MISO TOs was far too short to reflect a normal risk premium. LPSC argues that a historic risk premium analysis should use the actualized returns on market equity and debt over a long period (i.e., using decades of data).[680] According to LPSC, it is circular and inaccurate to use returns allowed by regulators to determine the risk premium.[681] LPSC states that, in Opinion No. 551, the Commission used its own past allowed returns on equity to reach a decision. LPSC asserts that this methodology is completely circular, and that the circularity concerns cannot be dismissed on the basis that allowed returns presumably reflect market data, because this only mitigates the circularity problem.[682]

328. LPSC argues that the 77 basis point offset for every percentage change in the cost of debt means that the required return on equity is largely unrelated to the cost of debt. LPSC contends that there is no statistically-significant relationship between the cost of debt and investors' return on equity requirements.[683] LPSC acknowledges that MISO TOs' witness, Dr. Avera, found a strong statistical correlation between interest rates and risk premiums. However, LPSC asserts that this simply proved that Commission-allowed ROEs barely changed as bond yields fluctuated, and therefore – because the risk premium is defined as the difference between the ROE and bond yields – risk premiums of course

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[679] RPGI Initial Br. (I) at 36; RPGI Initial Br. (II) at 40.

[680] LPSC Initial Br. at 5-7, 29-31 (citing Morin at 115 (stating that the use of a short period would be defective)).

[681] *Id* at 5.

[682] *Id.* at 6-7 (citing Morin at 125). LPSC notes that Dr. Morin offers the opposite advice with respect to the comparable earnings approach: "[t]he historical book return on equity for regulated firms is not determined by competitive forces but instead reflects the past actions of regulatory commissions." *Id.* at 7, 32 (quoting Morin at 383).

[683] *Id.* at 6. LPSC also note that the 77 basis point offset conflicts with empirical research, which has found an approximately 50 basis point offset. *Id.*

changed in relation to changing bond yields.[684] LPSC argues that a regression of ROEs and bond yields, on the other hand, would show that there is no statistically significant relationship between the two.[685]

329. LPSC asserts that the Risk Premium methodology accepted in Opinion No. 551 substantially mirrors the past. LPSC notes that the returns allowed from 2006 through 2014 are mostly non-litigated cases, many of which involved the settlement of multiple issues, and closely mirrored prior results despite a significant reduction in interest rates. LPSC argues that, given the significant changes in capital markets, this mirror image could not have accurately depicted investor return requirements.[686]

E. OMS

330. OMS argues that the Commission, in Opinion No. 551, erred by relying on MISO TOs' Risk Premium analysis to justify a base ROE of 10.32 percent. OMS argues that a Risk Premium study that assumes a linear relationship between bond yields and cost of equity is incompatible with anomalous market conditions.[687] OMS argues that an analysis that incorporates ROE determinations from a period when the Commission was applying the single-stage DCF methodology, which the Commission no longer accepts, unreasonably perpetuates erroneous results.[688]

331. OMS asserts that, if the Commission nonetheless chooses to rely on a Risk Premium analysis, MISO TOs' Risk Premium analysis should not be used because it is flawed. First, OMS argues that the analysis included 15 cases involving incentive adders that merely reiterated a set of existing base ROEs between 11.14 percent and 12.38

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[684] *Id.* at 32-33. LPSC explains that he results would be even more statistically significant (in fact, the fit would be perfect) if the ROE did not change at all. *Id.* at 33.

[685] *Id.* at 34.

[686] *Id.* at 6. LPSC explains that parties settle for many reasons, such as trade-offs on other issues, cost of litigation, and competing objectives. LPSC asserts that the use of the results of settlements would require objective evidence linking allowed returns to market evidence. *Id.* at 31, 35, 42 (citing *Daubert v. Merrell Dow Pharmaceuticals, Inc.,* 43 F.3d 1311, 1317-19 (9th Cir. 1995)).

[687] OMS Rehearing Request at 20-21. OMS notes that Opinion No. 531 found that the relationship between cost of equity and Treasury bond yields has become unreliability in both magnitude. *Id.* at 21 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 159).

[688] *Id.* at 21-22.

percent that had already been approved. According to OMS, relying on these high base ROEs multiple times artificially inflates the results of the analysis. Second, OMS contends that it is improper to include Commission decisions that were the product of settlement or simply mentioned in the context of deciding whether to allow an ROE incentive adder. Third, OMS states that it is particularly troublesome for the Commission to use a Risk Premium analysis that includes the very 12.38 percent base ROE that Opinion No. 551 finds to be unjust and unreasonable. Fourth, OMS points to the lack of synchronism between ROE decisions and the bond yields to which they are compared. OMS explains that synchronizing the data points, by merely correcting the dates to reflect contemporaneous bond yields, has a significant effect on the results of the Risk Premium analysis.[689]

F. Trial Staff

332. Trial Staff explains that its witness Mr. Keyton made adjustments to improve the proposed Risk Premium analysis to ensure that the results are more timely and accurate.[690]First, Trial Staff explains that its witness, Mr. Keyton, removed any Commission-authorized ROE that was not developed using market data contemporaneous with the applicable bond yields. Trial Staff states that, in some cases, the market analysis had taken place years prior to a Commission order assigning an ROE to a utility. Trial Staff notes that, when utilities join an RTO, they are simply given the currently-effective RTO-wide ROE, which is not tied to the risks or cost of equity faced by the utilities at that time. Trial Staff argues that such ROEs do not reflect a cost of equity estimate that is contemporaneous with the bond yields used to calculate the risk premium. Trial Staff explains that, consequently, Mr. Keyton removed observations that were merely reapplication of existing ROEs.[691]

333. Mr. Keyton also contends that using past-authorized ROEs generate erroneous equity risk premiums since their inclusion results in overstated equity risk premiums for more recent years because the vintage ROEs do not reflect the fact that equity costs have fallen as bond yields have fallen. He posits that this contradicts prior Commission findings recognizing the relationship between the cost of equity and bond yields.[692]

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[689] *Id.* at 22-25 (citing App. 1).

[690] Trial Staff Initial Br. (I) at 20-24; Trial Staff Initial Br. (II) at 19-24.

[691] Trial Staff Initial Br. (I) at 22-23 (citing Keyton Aff. (I) at 43-45); Trial Staff Initial Br. (II) at 21-22 (citing Keyton Aff. (II) at 42-43).

[692] Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 29 (citing Opinion No. 314, 44 FERC at 61,952 n.11, *order on reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252, *reh'g denied*, 46 FERC ¶ 61,036 (1989) and Order No. 489, FERC Stats. & Regs. ¶ 30,795 at

Mr. Keyton also states that Dr. Morin and Dr. Eugene F. Brigham have both noted the general relationship between interest rates and the cost of equity, which move in the same direction.[693]

334. Second, Trial Staff argues that that the MISO TOs' Risk Premium approach should have removed equity risk premiums between 2008 and 2009 that were impacted by bond yield spikes corresponding to the financial crisis.[694] According to Trial Staff, Mr. Keyton removed the six-month average Moody's Baa bond yields for the months from October to December 2008 and January to August 2009. Trial Staff explains that Mr. Keyton removed the bond yields from October to December 2008 because the yields suddenly rose by 143 basis points, and that he removed the bond yields from January to August 2009 because those yields were in steady decline until they stabilized in September 2009. Trial Staff explains that these removal adjustments were made because a risk premium calculated during a time of bond yield spikes will understate the actual risk premium required by investors.[695] Mr. Keyton notes that Mr. McKenzie acknowledged that there was no indication that a particular Commission-authorized ROE was derived to account for these spikes in bond yields.[696]

335. Trial Staff notes that MISO TOs now support use of a Risk Premium analysis based on both historical and projected bond yields, as apparently supported in the *Coakley* Briefing Order.[697] Trial Staff posits that the use of projected bond yields in the Risk Premium analysis referenced in the *Coakley* Briefing Order was inadvertent. Trial Staff notes that Opinion No. 551 clearly articulated why use of projected bond yields in

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30,993, *reh'g denied*, Order No. 489-A, 42 FERC ¶ 61,390); Trial Staff Reply Br. (II), Keyton Reply Aff. (II) at 24 (citing same).

[693] Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 29-30 (citing Morin at 383 and Eugene F. Brigham, *Financial Management: Theory and Practice* 21-22 (1979)); Trial Staff Reply Br. (II), Keyton Reply Aff. (II) at 24-25 (citing same).

[694] Trial Staff Initial Br. (I) at 23-24; Trial Staff Initial Br. (II) at 22-23; Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 28; Trial Staff Reply Br. (II), Keyton Aff. (II) at 23.

[695] Trial Staff Initial Br. (I) at 23-24 (citing Keyton Aff. (I) at ¶¶ 69-72); Trial Staff Initial Br. (II) at 22-23 (citing Keyton Aff. (II) at ¶¶ 69-70).

[696] Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 28.

[697] Trial Staff Reply Br. (I) at 12 (citing MISO TOs Initial Br. (I) at 24); Trial Staff Reply Br. (II) at 12 (citing MISO TOs Initial Br. (II) at 39-40).

the Risk Premium analysis is inappropriate, finding that "projected yields used in risk premium analyses are speculative and less reliable than historical yields."[698] Trial Staff adds that, for the fluctuations in the cost of equity to be captured by the Risk Premium model, the Commission must eliminate inputs that are speculative, inaccurate, or unreliable.

G. MISO TOs

336. In response to briefs opposing implementation of the MISO TOs' Risk Premium model, MISO TOs observe that the Commission accepted similar use of the Risk Premium analyses in Opinion No. 551 and found it to be similar to the analysis that it accepted in Opinion No. 531-B.[699] MISO TOs aver that opposing parties fail to raise new arguments that were not considered in those orders. Additionally, in response to arguments that their Risk Premium methodology inappropriately relies on settlement agreements, MISO TOs observe that the Commission, in Opinion No. 531-B, found that the use of settlements "do[] not affect that reliability of the risk premium analysis,"[700] and MISO TOs explain that, just as with litigated ROE outcomes, settling parties "rely upon the same market-based methodologies in determining the rates they are willing to accept."[701] MISO TOs further argue that, in each of the cases that other parties criticize, the Commission nonetheless ruled that the ROE at issue resulted in rates that were just and reasonable.[702] MISO TOs also reject arguments that the ROE inputs should align more closely with contemporary bond yields, noting that the Commission already found such precision to be overly difficult.[703]

337. MISO TOs also disagree with criticisms of the inverse relationship between equity risk premiums and interest rates. They note that the Commission, consistent with

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[698] Trial Staff Reply Br. (I) at 13 (citing Opinion No. 551 at P 194); Trial Staff Reply Br. (II) at 13 (citing same).

[699] MISO TOs Reply Br. (I) at 30-31 (citing Opinion No. 551, 156 FERC ¶ 61,234 at PP 191-200); MISO TOs Reply Br. (II) at 30-31 (citing same).

[700] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98.

[701] MISO TOs Reply Br. (I) at 31-32 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98); MISO TOs Reply Br. (II) at 31-32 (citing same).

[702] MISO TOs Reply Br. (I), App. 2 at 45; MISO TOs Reply Br. (II), App. 2 at 45.

[703] MISO TOs Reply Br. (I) at 32 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98); MISO TOs Reply Br. (II) at 32 (citing same).

financial literature, has recognized this relationship.[704] MISO TOs aver that the CAPs offer no empirical evidence or academic literature to support their argument that investment risk differentials reflected in yield spreads have a material effect on the behavior of equity risk premiums. With respect to the LPSC's assertions of the circulatory of this approach, MISO TOs state that Dr. Morin, who the LPSC cites, found that such circulatory concerns are mitigated in the risk premium context because the Commission-approved ROs are "presumably based on the results of market-based methodologies."[705]

338. MISO TOs disagree with Trial Staff's recommendation to remove bond yields associated with periods of volatility. They aver that doing so would ignore relevant observations and undermine the integrity of the risk premium model by enabling analysts to selectively parse monthly bond yield average data. MISO TOs also contend that using annual, averaged Baa utility bond yields, as they propose, washes out some of the monthly volatility.[706]

339. MISO TOs also assert that the Risk Premium model is a traditional method that investors use to estimate the expected return from an investment in a company[707] and that approved ROEs, which are inputs in the Risk Premium model, are closely followed by investors, and provide a direct signal that influences their expectations and required rates of return.[708]

H. Commission Determination

340. Based on full consideration of the record in this proceeding, we will not use the Risk Premium model, as proposed by the MISO TOs, in the Commission's ROE methodology, either for determining the justness of and reasonableness of existing ROEs under the first prong of section 206 or for determining new just and reasonable base ROEs under the second prong of section 206. In light of the evidence in the record regarding the Risk Premium model and the other models that we proposed to use in the

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[704] MISO TOs Reply Br. (I) at 33 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 99; Opinion No. 551, 156 FERC ¶ 61,234 at P 197; Morin at 128); MISO TOs Reply Br. (II) at 33 (citing same).

[705] MISO TOs Reply Br. (I) at 34 (citing Morin at 125); MISO TOs Reply Br. (II) at 34 (citing same).

[706] MISO TOs Reply Br. (I) at 34-35; MISO TOs Reply Br. (II) at 34-35.

[707] MISO TOs Reply Br. (I) at 30; MISO TOs Reply Br. (II) at 30.

[708] MISO TOs Reply Br. (I), App. 2 at 44; MISO TOs Reply Br. (II), App. 2 at 44.

Briefing Order, we conclude that the additional robustness that the Risk Premium model adds to the ROE determination is outweighed by the disadvantages of its deficiencies, as discussed below. Furthermore, we find that the model requires methodological decisions that would likely undermine transparency and predictability in Commission outcomes, which are valued by both investors and customers.

341. As an initial matter, the Risk Premium model is largely redundant with the CAPM. Although they rely on different data sources to determine the risk premium, both models use indirect measures (i.e., past Commission orders in the Risk Premium model and S&P 500 data in the CAPM) to ascertain the risk premium that investors require over the risk-free rate of return. We find that using the Risk Premium model in conjunction with the CAPM model would confer too much weight towards risk premium methodologies. The Commission has long used and, over time, refined the DCF model and we find that it would be inappropriate for variations of the risk premium model to receive twice its weight. In light of the disadvantages of the Risk Premium model discussed below and the similarity of the CAPM and Risk Premium models, we find that it is more appropriate to use only the CAPM to provide a risk premium-based cost of equity estimate.

342. In addition, we agree with CAPs that the Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data.[709] For example, previous ROE determinations may not involve an explicit determination as to whether an ROE is just and reasonable, but instead focused on whether to allow an ROE incentive adder or were approving a preexisting RTO-wide ROE for a new RTO member. Similarly, many previous ROE determinations used in the Risk Premium model were the product of rate case settlements. Such settlements often involve compromises on a variety of issues present in a rate case, of which the appropriate ROE is only one. Consequently, such settlements could include ROEs that are not representative of the market cost of equity because the ROEs were negotiated above or below that market cost of equity in order to form an overall settlement package, together with negotiated outcomes on other issues, that were acceptable to the parties.

343. While all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions. MISO TOs' regression analysis, discussed below, accentuates such circularity by largely offsetting the effects of changes in interest rates. As a result, we share the concerns expressed by various parties that the circularity inherent in the Risk Premium model's use of prior ROE determinations would largely

[709] *See* CAPs Reply Br. (I) at 26; CAPs Reply Br. (II) at 46.

continue previously-approved ROEs and reflect past circumstances that influenced the previous ROE decisions.[710]

344. We also question the application of the regression analyses used by MISO TOs in their Risk Premium model. These regressions, which have the impact of increasing the risk premium by 75 basis points for every 100 basis point decline in interest rates,[711] contrast starkly with Dr. Morin's analysis, which made that adjustment 48 basis points. This could be due to the length of time examined by the MISO TOs being less than half of the 18 years of regulatory decisions analyzed by Dr. Morin.[712] We note that, unlike for DCF and CAPM calculations, MISO TOs did not update and add to the data set for ROE proceedings through the end of the test period in June of 2015, further reducing the robustness of the data set. MISO TOs' regression in the first proceeding, by using the average of ROEs from each year, only has nine observations in its regression analysis, which is a low figure for a regression analysis, and therefore could impact the reliability of the results. Regardless of the reason for the high regression results, the MISO TOs' regression creates a dynamic where, regardless of the capital market conditions, the Risk Premium analysis will keep the ROE essentially stable. This defies general financial logic that lower interest rates make it easier to raise capital based on the reduced opportunity cost of bonds and greater availability of revenue to invest due to the opportunity for carry trades where borrowing low-cost debt is used to finance equity purchases. This relationship is evident when the stock market increases or decreases inversely with news regarding Federal Reserve interest rate activity. Additionally, the results of MISO TOs' regression analyses imply that the Federal Reserve's activities following the financial crisis in terms of reducing interest rates and open market operations had virtually no effect on the underlying required return on equity.

345. Additionally, the record contains insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions. Investors certainly observe regulatory ROEs and how changes in authorized ROE levels could affect utility earnings, but such considerations differ from the type of analyses employed by the MISO TOs looking back at past decisions to determine the current cost

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[710] *See, e.g.*, CAPs Reply Br. (I) at 26 ("[A] Risk Premium-based finding will tend to replicate the regulatory lag and inertial continuation of past returns that affected past regulatory decisions."); CAPs Reply Br. (II) at 46; LPSC Initial Br. at 6-7; OMS Rehearing Request at 20-21.

[711] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I), Attachment 6, at 6.

[712] Morin at 123.

of capital. We recognize that academic literature discusses this methodology, but the record indicates the greater prevalence of other methods.

346. The Risk Premium methodology also entails numerous judgement calls and corresponding points of dispute among parties that would render the model results less predictable and transparent than other models. First, as illustrated in this proceeding, there would likely be vigorous debate on which past ROE determinations the analysis should include. First, there is the issue of how far back such data should go. MISO TOs propose to start their analysis after the Energy Policy Act of 2005. This creates, at least for the time being, a much smaller data set than that which was used by Dr. Morin. We find unpersuasive MISO TOs' arguments that the nature of the industry and the resulting risk premiums changed due to this legislation sufficiently to ignore prior data. FPA section 219 requiring the Commission to provide transmission incentives is not germane to the base ROE determinations, nor are changes to the Public Utility Regulatory Policies Act, Commission enforcement authority, federal citing authority, or other elements of the 2005 Energy Policy Act. With that said, there is no clear initial starting point, which could be subject to debate.

347. In Opinion No. 531, the Commission found that "whether the regulatory decision involved a settlement agreement or the application of a cost of equity that was calculated in the past, e.g., the 12.38 percent ROE established for the MISO region, does not affect the reliability of a risk premium analysis."[713] Upon further review, we find that such application of past ROEs and settlements are not in all cases appropriate. In certain proceedings involving the admittance of new members to RTOs, the pleadings and resulting Commission orders did not reexamine the justness and reasonableness of the existing ROEs. Consequently, it is not reasonable to infer that the ROEs applied in these proceedings are the result of contemporary Commission analysis and representative of the cost of capital at that time. The same rationale applies to certain proceedings involving transmission incentives. In some cases, the Commission has explicitly examined the base ROEs or zones of reasonableness,[714] while in others the Commission has stated that the base ROE is beyond the scope of the proceeding, rendering it hard to argue that the resulting ROEs reflected contemporary risk premiums.[715] Consequently, it is highly debatable, as illustrated in this proceeding, which ROE proceedings the Commission should include in a Risk Premium analysis.

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[713] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98.

[714] *See Dusqesne Light*, 125 FERC ¶ 61,028 (2008).

[715] *See Pub. Serv. Elec. and Gas Co.,* 147 ¶ FERC 61,142, at P 48 (2014).

348. Order No. 531-B also found that "[g]iven the varying duration of regulatory proceedings, it is difficult, if not impossible, to ensure precise contemporaneity between long-term Treasury bond yields and the cost of equity allowed by a regulator."[716] Although an analysis with such imprecision may have been sufficient for using the Risk Premium model for corroborative purposes, we find that direct use of the model would require actual alignment of the test periods and the dates assigned for purposes of comparing the ROE to the risk free rate of return to determine the risk premium. In particular, orders on initial decision often occur more than a year following the updated test period.[717] It is unclear what test period should be assumed for orders in other types of proceedings, such as those approving transmission incentives. If the Commission were to adopt a precise timing in this proceeding, as a practical matter, such a decision would likely require the Commission to exclude certain proceedings whose test periods predate 2006 and include others, as well as potentially change the dates assigned to yet other proceedings.

349. Other debatable input decisions also bedevil the Risk Premium methodology, such that the Commission would need to resolve numerous implementation questions to enable its use. For instance, what is the risk premium resulting from proceedings resolved by settlements with different ROEs for different parties or time periods? Should multiple ROEs from the same proceeding be given more weight than individual ROEs from other proceedings? Where different ROEs apply to different time periods, should the ROEs be assigned to different times for purposes of the risk premium analysis? Should ROEs from settlements resolving multiple proceedings with the same ROE be counted once or twice? Other methodological decisions include whether to look at the annual average of ROEs and corresponding risk-free rates of return or look at them individually. The former avoids overweighting proceedings from years with many proceedings but greatly reduces precision by muting changes in ROEs and risk free rates of returns within years. Other points of disagreement include the appropriateness of using risk premiums from periods of high bond volatility, and whether to include state ROEs.

350. Such questions illustrate the inherent imprecision and complexity of this approach. We find that, although certain elements of the CAPM and DCF are subject to debate, as discussed above, the Risk Premium model features far more ambiguity and potential for dispute. Although the Commission could provide guidance on some of these matters, others would require ongoing adjudication. As a result, the Risk Premium model would lead to higher costs for participation by interested parties and reduced predictability of results, which both investors and customers value. Additionally, as discussed above, in

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[716] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98.

[717] *See* Opinion No. 551 which was issued 13 months following the end of the test period.

both proceedings before us here, the parties make numerous arguments supporting and opposing various specific aspects of how the Risk Premium model is implemented. For example, parties dispute whether or not to use settlements as inputs to the Risk Premium model,[718] how the time periods that are used for the comparison of bond yields and allowed ROEs should align,[719] whether to exclude bond yields from periods of high volatility,[720] and whether to use real or nominal bond yields in the Risk Premium analysis.[721]

351. Moreover, as noted in the Briefing Order, the output that the Risk Premium model produces is a single numerical point, and therefore, it does not produce a range which can be used to determine a zone of reasonableness. Accordingly, the Briefing Order proposed to only use the Risk Premium model in the second prong of the section 206 analysis where we determine a specific just and reasonable ROE, but not in the first prong of the analysis, which requires models that produce a range that can be used to determine a zone of reasonableness. This asymmetry in the potential use of the Risk Premium is not ideal and is another disadvantage of the Risk Premium model that weighs in favor of excluding it from the Commission's ROE methodology. We would prefer to use the same models in the prong one and prong two analyses to ensure that our ROE determinations under each prong are based on the same data and models. It would not be logical to use different models and data sources to apply this same standard under the two prongs unless there is some compelling justification for the difference. We find that there is no such compelling justification. We initially proposed to use the Risk Premium model, despite it only being appropriate for use in the second prong analysis, because our initial analysis of the model indicated that it could potentially provide benefits to our ROE methodology that outweighed the disadvantages of only having the model available for use in the second prong analysis. However, in light of the full record in these proceedings before us now, we find that the Risk Premium model does not provide benefits to our ROE methodology that would outweigh the model's disadvantages, such as the disadvantage of only having the model available for use in the second prong analysis.

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[718] *See, e.g.*, CAPs Br. on Exceptions at 65-59; MISO TOs Br. Opposing Exceptions at 57-58; MISO TOs Reply Br. (I) at 31-32.

[719] *See, e.g.*, OMS Rehearing Request at 23-25; RPGI Initial Br. (I) at 36–37; Trial Staff Initial Br. (I) at 21–23; MISO TOs Reply Br. (I) at 32.

[720] *See, e.g.*, Trial Staff Initial Br. (I) at 23-24; MISO TOs Reply Br. (I) at 34-35.

[721] *See, e.g.*, CAPs Br. on Exceptions at 50-52; OMS-JCA Br. on Exceptions at 47-48; MISO TOs Br. Opposing Exceptions at 58-59.

352. As discussed above, we will not use the Risk Premium model in our ROE methodology. Accordingly, we find that the parties' arguments regarding how the Risk Premium model should be implemented are moot and we will not address any such arguments raised in the briefs on and opposing exceptions to Initial Decision (II), requests for rehearing of Opinion No. 551, the initial and reply briefs issued in response to the Briefing Order, or any pleadings in these proceedings. We address some of these implementation issues in the context of discussing our decision to not use the Risk Premium model above, but in light of our decision not to use the model, we find that it is unnecessary to reach determinations on how the model should be implemented. Accordingly, we find that arguments in these proceedings regarding how the Risk Premium model should be implemented are moot.

IX. Potential Consideration of State ROEs

A. Briefing Order Proposal

353. In the Briefing Order, the Commission proposed to not consider the level of state ROEs when determining the composite zone of reasonableness under the first prong of section 206, nor to weight state ROEs equally with the financial models in establishing a new just and reasonable ROE under the second prong of section 206. However, the Commission proposed to consider evidence of state ROEs to the extent that the record adequately demonstrates that investors are using them to inform their investment decisions.[722]

B. CAPs

354. CAPs argue that the Commission's proposal is arbitrary and capricious for several reasons.[723] CAPs contend that the proposal departs from precedent rejecting direct use of state-authorized ROEs in establishing the Commission-jurisdictional return of utilities.[724] They assert that "Commission precedent rejects the direct use of state commissions' return determinations in setting [Commission]-jurisdictional ROEs."[725]

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[722] Briefing Order, 165 FERC ¶ 61,118 at P 37 n.67.

[723] CAPs Initial Br. (I) at 48; CAPs Initial Br. (II) at 48.

[724] CAPs Initial Br. (I) at 49; CAPs Initial Br. (II) at 49.

[725] CAPs Initial Br. (I) at 49 (citing, e.g., *Middle South Services, Inc.,* Opinion No. 124, 16 FERC ¶ 61,101 (1981*)*; *Boston Edison Co.,* Opinion No. 411, 77 FERC ¶ 61,272 (1996); *Jersey Cent. Power & Light Co.,* Opinion No. 408, 77 FERC ¶ 61,001 (1996); *Appalachian Power Co.*, Opinion No. 423, 83 FERC ¶ 61,335 (1998); *Midwest*

CAPs contend that in Opinion Nos. 531 and 531-B the Commission acknowledged and reaffirmed this precedent. They argue that the Commission has not explained "how its proposed use of state-authorized ROEs would be consistent with precedent, or why departure from its precedent would be appropriate."[726] CAPs further assert that "[i]n *Emera Maine*, the D.C. Circuit found it arbitrary and capricious to use state-allowed ROEs to support placement of the New England TOs' ROE at the upper midpoint because state-authorized ROE data pointed to a level below the DCF upper midpoint."[727] CAPs also contend that the Commission does not explain why it may be appropriate to use state-authorized ROEs in the second prong of section 206 proceedings (i.e., to establish the new just and reasonable ROE), but that it is never appropriate to use such data in the first prong of section 206 (i.e., to determine whether the existing ROE of utilities is unjust and unreasonable).[728]

355. CAPs assert that the Commission proposes to disregard considering state-authorized ROEs in the formation of the composite zone of reasonableness at the same time that it is proposing to consider such data in the calculation of a replacement ROE. CAPs argue that, if evidence in the record shows that investors rely on state-authorized ROE data, it follows that investors' return expectations based on this data is as relevant to determining whether the existing ROE is unjust and unreasonable as it is to determining the replacement ROE and the total ROE cap.[729] Hence, CAPs contend that the Commission is proposing an inconsistent application of state-authorized ROE evidence without providing a reasonable explanation for doing so.[730] Further, CAPs argue that the Commission has not explained what weight state-authorized ROEs will be given or what type of evidence could show that investors rely on these ROEs.[731]

356. CAPs comment that the use of state-authorized ROEs by the Commission would not satisfy the comparability standard of *Hope* and *Bluefield*, which requires that a

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Independent Transmission System Operator, Inc., 98 FERC ¶ 61,356, at 62,525 n.15 (2002)); CAPs Initial Br. (II) at 49 (citing same).

[726] CAPs Initial Br. (I) at 50; CAPs Initial Br. (II) at 50.

[727] CAPs Initial Br. (I) at 50; CAPs Initial Br. (II) at 50.

[728] CAPs Initial Br. (I) at 48; CAPs Initial Br. (II) at 48.

[729] CAPs Initial Br. (I) at 51; CAPs Initial Br. (II) at 51.

[730] CAPs Initial Br. (I) at 52; CAPs Initial Br. (II) at 51.

[731] CAPs Initial Br. (I) at 52; CAPs Initial Br. (II) at 51.

utility's return on equity must be "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties."[732] CAPs argue that state commissions establish ROEs having taken into account a wide range of risk factors that are unique to each state, vary across jurisdictions and change over time. According to CAPs, state ROEs reflect considerations that are completely unrelated to the transmission risks that the base ROE in this case sees to account for.[733]

357. Finally, CAPs assert that, to the extent that the Commission decides to use state-authorized ROE data in its ROE determinations, it should establish generic, transparent criteria to ensure appropriate comparability, and that the state-authorized ROE data should be used in a consistent manner, regardless of whether the data increases or lowers the base ROE.[734]

C. Alliant

358. Alliant argues that the Commission should compare the base ROE resulting from its proposed methodology to retail utility ROEs allowed in states in which transmission facilities owned by each of the MISO TOs are located. Alliant contends that the ROE established by the Commission for unbundled transmission service within a state should be consistent with the ROE permitted by state regulators for retail rates because state regulators also have the obligation to ensure that charges for bundled electric service by retail electric service customers are just and reasonable.[735]

D. MISO TOs

359. In their reply brief, the MISO TOs assert that, contrary to arguments presented by CAPs, the Commission has ample justification in the record of the First and Second Complaint proceedings for considering state-authorized ROEs as evidence of expected investor returns.[736] Further, they endorse the Commission considering state-authorized ROEs in the context of how the risk profile of a state-regulated utility compares to the

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[732] CAPs Initial Br. (I) at 52 (quoting *Bluefield*, 262 U.S. at 692); CAPs Initial Br. (II) at 52 (quoting same).

[733] CAPs Initial Br. (I) at 53; CAPs Initial Br. (II) at 52.

[734] CAPs Initial Br. (I) at 53; CAPs Initial Br. (II) at 53.

[735] Alliant Initial Br. at 10-11.

[736] *See* MISO TOs Reply Br. (I) at 82.

risk profile of the MISO Transmission Owners, and argue that consideration of state-authorized ROEs is consistent with Opinion No. 531-B. MISO TOs also assert that CAPs incorrectly characterizes the ruling in *Emera Maine* regarding the Commission's consideration of data for state-authorized ROEs. MISO TOs argue that the Court did not find error with the Commission's consideration of state ROE data. Rather, the Court determined that the Commission erred when it failed to provide a reasoned explanation relative to the cited state-authorized ROEs and other evidence.[737]

360. In response to CAPs' assertion that the Commission in the First Complaint proceeding did not find that investors had relied upon state-authorized ROE, MISO TOs argue that it is illogical to conclude that there was not a showing that investors relied on such data. MISO TOs argue that the Commission did not need to specifically rely on evidence of state-authorized ROEs in order to present the methodology and findings it proposed in the Briefing Order.[738]

361. MISO TOs comment that CAPs misread the Commission's Briefing Order when they conclude that state-authorized ROEs will not be used in evaluating an existing ROE for justness and reasonableness under prong one of the FPA section 206 analysis.[739] Instead, MISO TOs assert that the Commission explains in the Briefing Order that it will not use state-authorized ROEs in the composition of the composite zone of reasonableness in prong one of PFA section 206, nor as one of the four financial models used to establish a new base ROE in prong two of FPA section 206. Nonetheless, MISO TOs assert that in the Briefing Order the Commission leaves open other purposes for which the Commission could consider state-authorized ROEs in both prongs of the FPA section 206.[740] MISO TOs argue that, contrary to CAP comments, the state ROE data cannot be used to calculate a composite zone of reasonableness because there are material risk differences between utilities regulated at the state level and the transmission utilities regulated at the federal level.[741] Rather, MISO TOs assert that state-authorized ROE data

[737] *Id.* at 83-84.

[738] *Id.* at 84.

[739] *Id.* at 85 (citing Briefing Order, 165 FERC ¶ 61,118 at P 37 n.67).

[740] *Id.* at 85-86.

[741] *Id.* at 86.

has been and can be a useful tool as a benchmark in reviewing investor expectations and evaluations cost of equity estimates within the larger market context.[742]

362. Finally, MISO TOs respond to CAPs request that the Commission adopt a generic and transparent criteria when using data on state-authorized ROEs by asserting that this request seeks a superfluous legal standard that is unnecessary, outside of the scope of this proceeding and would have no discernable benefit.[743]

E. Commission Determination

363. We continue to find that our ROE determination in these proceedings need not consider state-authorized ROEs. As MISO TOs point out, there are material differences between state and Commission ROEs. As an initial matter, state-authorized ROEs may apply to distribution companies, which feature lower risks than transmission companies subject to Commission ROEs. Also, certain states include shared savings, decoupling, or performance-based rates, rendering comparisons between Commission and state ROEs less precise. As a result, we will only consider state-authorized ROEs on a case-by-case basis to the extent that they demonstrate that the results of the Commission's CAPM and DCF analyses are substantially excessive or deficient. We do not expect that the Commission will regularly consider state-authorized ROEs. Rather, they serve as a check given the model risk as we formulate our ROE determinations.

364. We also clarify that state ROE information could inform both prongs of the section 206 ROE analysis. For the first prong, such information could be used to rebut the presumption that a given base ROE is or is not just and reasonable. Such information could also be used to demonstrate, for instance, that the base ROE established under the second prong is substantially excessive or deficient. We also reject Alliant's proposal to use state ROEs where the utility is located. Doing so would potentially tie Commission ROE determinations to state determinations, which could be methodologically very different or apply to utilities featuring different risk profiles than Commission-jurisdictional transmission owners.

X. Proxy Group Construction

365. Both the DCF and CAPM models use proxy groups to determine a range of reasonable returns. In the Briefing Order,[744] the Commission stated that it intends to

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[742] *Id.* at 86.

[743] *Id.* at 86-87.

[744] *Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 51.

continue to use the same screens for developing a proxy group as the Commission has used in recent cases, including Opinion Nos. 531[745] and 551.[746] Those five screens are: (1) the use of a national group of companies considered electric utilities by *Value Line*;[747] (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose ROE is at issue;[748] (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six month study period;[749] (4) the inclusion of companies with no merger activity during the six-month study period that is significant enough to distort the study inputs;[750] and (5) companies whose ROE results pass threshold tests of economic logic, including both a low-end outlier test and a revised high-end outlier test proposed in the Briefing Order.

366. The first four screens listed above evaluate particular characteristics potential proxy group companies. They do not vary depending upon the results of the DCF or CAPM analyses. Accordingly, those screens may be used to develop a starting group of proxy companies eligible for inclusion in the proxy group to be used for the purposes of both the DCF and CAPM analyses. However, the high-end outlier test part of the last screen—whether the company's cost of equity estimate passes threshold tests of economic logic—depends upon the median cost of equity estimate each of the two models produces. Thus, in determining the zone of reasonableness produced by each of these models, the high-end outlier test must be applied separately to each model. Below, we discuss issues raised by the participants with respect to the high-end and low-end outlier tests. By contrast, the low-end outlier test for both models is derived, in part from, the CAPM's risk premium.

A. High End Outlier Test

1. Briefing Order

367. In the Briefing Orders, the Commission recognized that the CAPM model can produce unsustainably high results for a particular proxy company, because, unlike the

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[745] Opinion No. 531, 147 FERC ¶ 61,234 at P 97.

[746] Opinion No. 551, 156 FERC ¶ 61,234 at P 20.

[747] Opinion No. 531, 147 FERC ¶ 61,234 at PP 96, 100-102.

[748] The Commission requires use of both Standard and Poor's corporate credit ratings and Moody's issuer ratings when both are available. *Id.* P 107.

[749] *Id.* P 112.

[750] *Id.* P 114; Opinion No. 551, 156 FERC ¶ 61,234 at PP 37-43.

two-step DCF analysis, it does not include a long-term growth projection based on GDP that would normalize the ROEs produced by the model, similar to that used in the two-step DCF analysis. Moreover, the Commission recognized that in unusual circumstances, the two-step DCF analysis could also produce unsustainably high results. Therefore, the Commission proposed to apply a high-end outlier test to the results of both these models.

368. The Commission proposed to treat as high-end outliers any proxy company whose cost of equity estimated under the model in question is more than 150 percent of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis similar to the approach the Commission uses for low-end DCF analysis results. The Commission stated that this test should identify those companies whose cost of equity under the model in question is so far above the cost of equity of a typical proxy company as to suggest that it is the result of atypical circumstances that are not representative of the risk profile of a more normal utility.

2. CAPs

369. MISO CAPs contend that a high-end outlier test should be used, particularly if the Commission sets the base ROE based mainly on the midpoint rather than the median of the zone of reasonableness. However, CAPs contend that the Commission's proposed high-end outlier test lacks a statistically sound basis and does not appropriately consider information inherent in the underlying array of ROEs produced by each financial model. MISO CAPs recommend the Commission should, instead, exclude as high-end outliers any ROEs produced by each model that are more than two standard deviations[751] above the median of the ROEs produced by that model.[752] MISO CAPs state that MISO TOs'

[751] In statistics, a standard deviation is a measure that is used to quantify the amount of variation or dispersion on a set of values. The smaller the standard deviation, the more values that are expected to be closer to the mean. Conversely, a large standard deviation implies that the data is more widely distributed. Under a normal distribution, only 2.5 percent of observations are expected to be more than two standard deviations above the mean.

[752] CAPS Initial Br. (I) at 60-63, Ex. JCI-100 (Solomon Testimony) at 13-14, CAPS Initial Br. (II) at 60-63, Ex. JCI-200 at 12-13. In reply briefs, MISO CAPS also alternatively endorse use of the Grubbs test, another statistical method for identifying outliers, over MISO TOs' proposals. *See* CAPS Reply Br. (I) at 60.

proposed alternative threshold, which is 150 percent of the highest median return on equity from all three models, has no economic basis.[753]

3. MISO TOs

370. MISO TOs oppose the use of any high-end outlier test.[754] MISO TOs contend that the 150 percent threshold test is arbitrary and not tied to previous Commission policy. MISO TOs specifically assert that there is no support for the contention that an estimate greater than 1.5 times the median of a model's range of estimates must be the result of "atypical circumstances." MISO TOs also contend that there has been no showing that investors generally disregard high-end estimates from any model or rely on the proposed 150 percent test to eliminate high-end results.

371. MISO TOs also oppose CAPs' alternative statistical tests based on a standard deviation. They assert that those tests relate to the practice of sampling, i.e., the selection of a subset of data from within a larger population that allows the researcher to make statistical inferences about unknown qualities of the population. MISO TOs assert that the CAPs' proposed tests are used to determine whether the sampling data represent a random sample from a single normal population. However, MISO TOs contend that, when the Commission selects a proxy group, it is not sampling. Rather, the Commission has identified all of the utilities deemed to be of comparable risk to the MISO TOs. Thus, the array of cost of equity estimates of the proxy companies represent a population, not a sample of the population. As a result, the dispersion of individual values around the population mean is not a valid test of how well a specific estimate reflects investors' expectations.[755] However, MISO TOs contend that, if the Commission does use a high-end outlier test, then it should apply that test to the highest median of the CAPM, Expected Earnings, and DCF models, and apply it only as a rebuttable presumption.

372. Further, MISO TOs contend that the high-end outlier test should not apply to the DCF model.[756] MISO TOs note that, in Opinion No. 531, the Commission stated that including long-term GDP growth in the two-step DCF eliminates the need to screen the results for high-end outliers. MISO TOs also assert that the median of the DCF results does not constitute a meaningful guide to investors' required returns given that the Commission has determined that the central tendency of the DCF zone of reasonableness

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[753] Ex. JCI-107 at 29-30 (Solomon Testimony).

[754] MISO TOs Initial Br. (I) at 12-16.

[755] MISO TOs Initial Br. (I), App. 2 McKenzie Reply Aff. (I) at 100-102.

[756] MISO TOs Initial Br. (I) at 16-18.

may be distorted by anomalous capital market conditions as the Commission found in Opinion Nos. 531 and 551. MISO TOs contend that, if the Commission does apply the high-end outlier test to the DCF model, then it should employ the one-step DCF model without any long-term growth projection.

4. Trial Staff

373. In its reply brief, Trial Staff supports the high-end outlier test proposed in the Briefing Order and opposes the MISO TOs' contention that a high-end outlier test is unnecessary.[757]

5. Other Parties

374. RPGI supports the high-end outlier test proposed by the Briefing Order.[758]

6. Commission Determination

375. We adopt the high-end outlier test proposed in the Briefing Order. Although we have decided not to use the Expected Earnings model, which is more subject to high-end outliers than the other models, or the Risk Premium Model, the other models may produce unsustainably high results for a particular proxy company in unusual situations. Therefore, we find it necessary to apply a high-end outlier test to the results of these methods. As shown with TECO,[759] whose IBES growth estimates changed from 6.43 to 9.2 and back to 7.68 percent during the course of the First Complaint proceeding, financial metrics for individual utilities can fluctuate dramatically, potentially affecting the resulting ROE. Particularly given that the Commission will continue to use the midpoint as the measure of central tendency for region-wide ROEs, as discussed below, we find it appropriate that there be a high-end outlier test to eliminate members of the proxy group whose ROEs are unreasonably high.

376. While parties have proposed alternative high-end outlier tests as being superior because they have a firmer statistical basis, we do not find these arguments persuasive. Statistical methodologies, like the proposed alternative outlier test methodologies, may be based on assumptions such as the distribution of the underlying population being

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[757] Trial Staff Reply Br. (I) at 6-7.

[758] RPGI Reply Br. (I) at 13-18.

[759] As noted above, in the First Complaint proceeding, TECO set the top of the zone of reasonableness.

normal.[760] These underlying assumptions may not always hold for a given proxy group, especially a small proxy group.[761] As stated in the article by Frank Grubbs cited by CAPs, "the rejection of 'outlying' observations may be just as much a practical (or common sense) problem as a statistical one and sometimes the practical or experimental viewpoint may naturally outweigh any statistical contributions in a sample . . . [A]ny test which requires an inordinate amount of calculation seems hardly to be worthwhile."[762] The high-end outlier test proposed in the Briefing Orders has the advantage that it is relatively easy to carry out and places a well-defined upper bound on the proxy group. In addition, because this test only utilizes a percentage differential compared to the median, it can be used with small proxy groups.

377. We also reject MISO TOs' proposal to use 150 percent of the highest median ROE produced by either the DCF or the CAPM model as the high-end outlier test for both models. As Mr. Solomon testified for CAPs, each model is based on different assumptions and thus estimates the cost of equity in different ways. Therefore, the determination of whether each model produces one or more extreme or illogical results is best determined by examining the dispersion of the ROE estimates produced by that model.[763]

378. MISO TOs also assert that, if the Commission applies a high-end outlier test to the DCF model, it should use a one-step DCF model without any long-term growth projection, instead of the two-step DCF model. However, the Commission has already discussed earlier in this order why a DCF analysis of a single utility should include a long-term growth projection. We recognize that the inclusion of a long-term growth projection based on GDP tends to normalize the ROEs produced by the model, and that this minimizes the likelihood that there will be any high-end outlier. Indeed, the high-end outlier test adopted in this order does not exclude any proxy company's DCF ROE in either the First Complaint or Second Complaint proceeding. Nonetheless, it is possible that unusual circumstances with respect to a particular company, if for example, there is an unusually high IBES growth projection as a company bounces back from a unique

[760] *See, e.g.*, MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 107 ("Under Mr. Solomon's paradigm, where the standard deviation serves as a relevant measure of dispersion, the distribution is assumed to be perfectly normal.").

[761] *See, e.g.*, *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002) (addressing a case where "the distribution of figures used to calculate Northwest's ROE is negatively skewed.").

[762] Frank Grubbs, Sample Criteria for Testing Outlying Observations, at 30.

[763] Ex. JCI-107 at 29.

setback, could cause the two-step DCF model to produce an illogically high ROE. The high-end outlier test adopted in this order allows such an illogical ROE to be excluded from the proxy group.

B. Low-End Outlier Test

1. Briefing Order

379. Under the Commission's existing low-end outlier test, companies whose ROE fails to exceed the average 10-year bond yield by approximately 100 basis points are excluded from the proxy group on the ground that investors generally cannot be expected to purchase a common stock if debt, which has less risk than a common stock, yields essentially the same expected return.[764] In the Briefing Order, the Commission proposed to continue to use this test for purposes of the CAPM and Expected Earnings analyses as well as the DCF analysis.[765]

2. MISO TOs

380. MISO TOs assert that the Commission adopted its current low-end outlier test in four ROE cases which used financial data for the six months ending November 2007 or the six months ending September 2008.[766] MISO TOs state that Baa bond yields over those two six-month periods averaged 6.69 percent.[767] However, Baa bond yields during the study period for the First Complaint proceeding (the six months ending June 2015) declined by 204 basis points to 4.65 percent,[768] and during the study period for the

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[764] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, at P 94 (2009) (*Pioneer)*, *reh'g denied*, 130 FERC ¶ 61,044 (2010). *S. Cal. Edison Co*., 131 FERC ¶ 61,020, at PP 54-56 (2010) (*SoCal Edison*). In *SoCal Edison*, the Commission stated that it also eliminated companies whose ROEs were less than 100 basis points above the Moody's bond yield for that particular rating in *Atlantic PATH 15*, 122 FERC ¶ 61,135 (2008) (*Atlantic PATH*) and in *Startrans IO. L.L.C.*, 122 FERC ¶ 61,306 (2008) (*Startrans*). *Id.* P 54.

[765] Briefing Order, 165 FERC ¶ 61,118 at P 52.

[766] MISO TOs Initial br. (I) App. 2 McKenzie Aff. (I) at 29 (citing *Pioneer*, 126 FERC ¶ 61,281; *SoCal Edison*, 131 FERC ¶ 61,020; *Atlantic PATH*, 122 FERC ¶ 61,135; and *Startrans*, 122 FERC ¶ 61,306).

[767] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 29-30.

[768] *Id*. at 31.

Second Complaint study period (the six months ending December 2015) declined by 128 basis points to 5.41 percent.[769] Accordingly, MISO TOs contend that the 100 basis point low-end threshold should be adjusted upwards to account for the inverse relationship between risk premiums and bond yields shown by their risk premium analysis in each case.[770] Under the MISO TOs' proposed method, the low end threshold would be adjusted upwards by 154 basis points[771] from 100 basis points to 254 basis points in the First Complaint proceeding, and by 91 basis points[772] to 191 basis points in the Second Complaint proceeding. Thus, in the First Complaint Proceeding the low-end outlier test would exclude from the proxy group any companies with ROEs of 7.19 percent or less and in the Second Complaint Proceeding the test would exclude companies with ROEs of 7.32 percent or less. MISO TOs contend that this revised test would justify excluding additional companies from the proxy groups used for the DCF analysis. The MISO TOs state that the revised low-end outlier test would not affect the proxy group used for the CAPM analysis.

381. Further, MISO TOs argue that the Commission's practice has been to compare every proxy company's ROE to Baa bond index yields. MISO TOs argue the Commission should continue to use Baa bond index yields for the low-end outlier test because that is the bond rating category closest to the risks of common stock.[773]

3. CAPs

382. CAPs oppose MISO TOs' proposed revision to the low-end outlier test.[774] CAPs point out that the Commission used the 100 basis point low-end outlier test in Opinion No. 551 in the First Complaint Proceeding, and the MISO TOs did not seek rehearing on

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[769] MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 27.

[770] MISO TOs Initial Br. (I), App. 2 McKenzie Aff. (I) at 28-31; MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 24-27.

[771] MISO TOs calculate this adjustment by multiplying the 204 basis point decline in interest rate by the 75.34 percent increase in the risk premium determined by its risk premium study in the First Complaint proceeding.

[772] MISO TOs calculate this adjustment by multiplying the 128 basis point decline in interest rate by the 71.56 percent increase in the risk premium determined by its risk premium study in the Second Complaint proceeding.

[773] MISO TOs Reply Br. (I) at 57-58.

[774] CAPs Reply Br. (I) at 48-59; Ex. JC-108 at 29.

that issue. Also, the Presiding Judge in the Second Complaint Proceeding used the 100 basis point low-end outlier test, and the MISO TOs did not file an exception on that issue.

383. CAPs assert that the Commission has explained that the "the purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[775] CAPs argue that, for purposes of determining whether a stock would be considered to yield essentially the same return as debt, the 100 basis point threshold is appropriate regardless of changes in interest rates. They assert that yield spreads of utility stock dividends over utility bond yields are relatively stable during most markets. The only notable exception would be during distressed markets when the market demands abnormal risk premiums to invest in securities of greater risk.[776]

384. CAPs also disagree with the MISO TOs' contention that, in applying the low-end outlier test, the ROE of every proxy company should be compared to the Baa bond yield. CAPs argue that the ROE of each proxy company should be compared to the yields of bonds with the same credit rating as the proxy company in question. Thus, if the proxy company has a credit rating of A, its ROE would be compared to A bond yields.[777]

4. Trial Staff

385. Trial Staff argues that MISO TOs' proposed modification to the low-end outlier test, which would require exclusion of companies with ROEs of 7.19 percent or less in the First Complaint Proceeding and companies with ROEs of 7.32 percent or less in the Second Complaint Proceeding, is illogical. Trial Staff contends that no rational investor would consider ROEs of 7.19 percent and 7.32 percent as "essentially the same return" as the contemporary Baa bond yields of 4.65 percent and 5.41 percent respectively.[778] Trial Staff also asserts that the adjustments proposed by MISO TOs rely on an arbitrary choice of time periods for a comparison of interest rates. Trial Staff states that the baseline 6.69 percent Baa bond yield staff used based on study periods in 2007 and 2008 was higher

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[775] CAPs Reply Br. (I) at 53-54 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 122).

[776] Ex. JC-108 at 30-32.

[777] Ex. JCI-100 at 12; Ex. JCI-107 at 8.

[778] Trial Staff Reply Br. (I) at 6 (citing Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 10-11). *See also* Trial Staff Reply Br. (II) at 5-6 (citing Trial Staff Reply Br. (II), Keyton Reply Aff. (II) at 10-11).

than the calendar year average Baa bond yields for every year since 2002, except for the bond yield spike period of 2008 and 2009.[779] Trial Staff asserts that it is arbitrary to assume that the baseline for the change in interest rates should be constrained to a comparison between the 2007 and 2008 study periods and the study periods for the First and Second Complaint Proceedings.

386. Trial Staff also states that, in applying the low-end outlier test, the ROE of each proxy company should be compared to the yields of bonds with the same credit rating as the proxy company in question.[780]

5. Commission Determination

387. We will adjust the low-end outlier test to include a risk premium instead of the generic 100 basis points proposed in the Briefing Order, as discussed below. In particular, we will adopt a revised low-end outlier test that eliminates proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20 percent of the CAPM risk premium. The purpose of the low-end outlier test is to eliminate from the proxy group companies with ROEs that are so low that they should not be considered in determining the low end of the zone of reasonableness. Thus, the mere fact a potential proxy company's ROE may be lower than what would be considered reasonable for an average risk, or even a below average risk, utility is not a sufficient reason to exclude the company from the proxy group. Instead, the Commission's standard has been to exclude companies whose ROEs yield "essentially the same expected return" as debt. As MISO TOs have argued, and the Commission has acknowledged, as bond yields decline, the ROE that investors would consider to yield "essentially the same expected return" as a bond is increasingly higher than the corresponding bond yield.[781] Thus, to ensure that the low-end outlier test properly excludes companies whose ROE is indistinguishable from debt, an adjustment accounting for this risk premium is necessary.

388. We find that 20 percent of the risk premium from the CAPM analysis described above is a reasonable risk premium to apply to the low-end outlier test. Because the risk premium that investors demand changes over time, it is imprecise to simply add 100 basis

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[779] Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 11.

[780] *Id*. at 11-12 (citing *Bangor Hydro-Electric Co*., Opinion No. 489, 117 FERC ¶ 61,129, at PP 56-60 (2006) and Opinion No. 445, 92 FERC at 61,266).

[781] See Morin at 128-129, summarizing empirical research showing that as interest rates decline, the risk premium required by equity investors increases. Morin concludes that the gist of this research is that for every 100 basis point decline in government bond yields, the equity risk premium increases by about 50 basis points.

points to the bond yield. The methodology that we are adopting in this order captures such changes because the risk premium from the CAPM analysis reflects investors' required risk premium under the prevailing market conditions. We find that the 20 percent portion of the risk premium strikes a proper balance by being sufficiently large to account for the additional risk of equities over bonds, but not so large as to inappropriately exclude proxy group members whose return on equity is distinguishable from debt. This raises the low-end outlier threshold in the First Complaint proceeding from 5.65 to 6.47 percent, and it raises the low-end outlier threshold in the Second Complaint proceeding from 6.41 to 7.18 percent.[782] This revision does not result in the exclusion of any additional companies from the proxy group when applied to either the DCF or CAPM analyses in the First Complaint proceeding. However, in the Second Complaint proceeding, the revised low-end outlier test excludes one additional company from the DCF analysis.

389. MISO TOs argue that the low-end outlier test has been and should be based on the average Baa yield, while CAPs argue that the application of the low-end outlier test should be dependent on the bond rating of each company in the proxy group. We note that the Commission has applied this test differently in the past, with the most recent application being to apply the test based on the average Baa yield.[783] Conversely, CAPs contend that the Commission should base the low-end outlier test on Moody's Public Utility Bond index yield for the same rating category proxy utility under consideration. While CAPs argue that this application would be more precise, we find that using the Baa bond yields as the low-end test is consistent with the Commission seeking the proxy group for a diverse group of utilities to be representative of the cost of capital for all of those utilities. Further, using the specific bond yield for each company, in addition to adding complexity to the calculations, renders them (and the resulting ROE) less predictable, as the credit ratings for individual companies are likely more volatile than the generic corporate rate baa credit rating due to company-specific credit rating considerations. As discussed elsewhere in this order, where possible, we seek to provide predictability and transparency to ROE determinations, which is best accomplished by using a single outlier test. We find no reason to adjust the low-end outlier test to be applied to Moody's Public Utility Bond index yield for the same rating category proxy utility under consideration at this time.

[782] *See* Appendix C. *See also* Opinion No. 551, 156 FERC ¶ 61,234 at P 20; Initial Decision (II), 155 FERC ¶ 63,030 at P 171 and P 174 n.75.

[783] Opinion No. 531, 147 FERC ¶ 61,234 at P 123.

C. Natural Break Analysis

1. Briefing Order

390. In the Briefing Orders, the Commission proposes to apply its low-end and high-end outlier screens, subject to a "natural break" analysis. The natural break analysis determines whether certain proxy group companies screened as outliers, or those almost screened as outliers, truly represent outliers and should thus be removed from the proxy group. Typically this involves examining the distance between that proxy group company and the next closest proxy group company, and comparing that to the dispersion of other proxy group companies.[784]

391. In the Briefing Orders, the Commission did not explicitly define how large of a difference constitutes a natural break, nor did it set forth a specific methodology for determining what constitutes a natural break. In Opinion No. 531, the Commission stated that there was a natural break where an excluded proxy group company had a cost of equity estimate that was 101 basis points above the applicable bond yield and the lowest cost of equity estimate of the included proxy group companies was 242 basis points above the applicable bond yield—or a 141 basis point break between the excluded and lowest included companies.[785] In Opinion 531-B, the Commission indicated that the same natural break analysis need not apply to both the low- and high-end outlier tests because those tests serve different purposes,[786] but did not otherwise define the numerical difference that would constitute a natural break or provide a methodology for determining what constitutes a natural break.

2. CAPs

392. CAPS contend that the natural break analysis should apply to low-end and high-end outliers.[787] However, CAPS argue that the natural break analysis is vague and subjective, and contend the Commission should use a more objective test. Specifically, CAPS propose the Commission use a two-part test that examines whether a proxy value is: (1) close to the threshold level that applies prior to considering natural breaks; and

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[784] *See, e.g., SoCal Edison*, 131 FERC ¶ 61,020 at P 56, applying a natural break analysis to exclude from the proxy group a company whose ROE was 102 basis points above the applicable bond yield.

[785] Opinion No. 531, 147 FERC ¶ 61,234 at P 123.

[786] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 79.

[787] CAPS Initial Br. (I) at 61.

(2) far from the neighboring proxy value that would be retained.[788] MISO CAPS contend that the population argument raised by MISO TOs is undermined by, among other things, the Commission's proxy group selection criteria having changed over time.[789]

3. MISO TOs

393. MISO TOs contend the Commission should not use the natural break analysis. Specifically, MISO TOs contend the test has no economic basis, is illogical, unnecessary, arbitrary, and highly subjective. MISO TOs contend the use of the natural break analysis is based on a false premise that evaluating cost of equity estimates is akin to sampling. Instead, MISO TOs contend that the Commission's proxy group criteria are designed to identify the entire relevant population. Further, the MISO TOs contend that the goal is not to exclude outliers, but to exclude estimates that are illogical for use as a basis for establishing the zone of reasonableness.[790] MISO TOs contend that, if the Commission elects to use a natural break analysis, it only be used on the low end of a cost-of-equity estimate range to determine whether the low-end outlier test may have failed to exclude illogical results.[791]

4. Trial Staff

394. Trial Staff contends a natural break test should be used, and argues that dispersion must be taken into consideration for the midpoint to pass the test of economic logic.[792]

5. Commission Determination

395. We will continue to apply the natural break analysis to our outlier screens. We do not find the arguments raised by MISO TOs against its use availing. As has been noted,

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[788] CAPS Initial Br. (I) at 61-64. The specific test CAPS proposes is detailed in Exhibit JCI-100 at 14-16. Specifically, this test first identifies whether the distance between the outlier threshold and the adjacent proxy value is less than the average jump, or the width of the distribution's range divided by the number of proxies. The test then identifies whether the distance between that lowest or highest proxy value and its neighbor is more than twice the jump separating that neighbor from the next neighbor.

[789] CAPS Reply Br. (I) at 75.

[790] MISO TOs Initial Br. (I) at 9-11.

[791] *Id.* at 11-12.

[792] Trial Staff Reply Br. (I), Keyton Reply Aff. (I) at 29.

the purpose of both the high and low-end outlier tests is to screen for outliers whose inclusion in the proxy group would lead to economically illogical results. Under both tests, as outlined in this order, the Commission will use a formula to calculate a specific numerical guideline for determining whether a particular company's DCF or CAPM ROE should be treated as a high or low-end outlier. However, any such specific numerical guideline must, of necessity, be somewhat arbitrary, given the insignificance of a few basis points difference in ROE. The natural break analysis gives the Commission the flexibility to determine whether a given proxy group company is truly an outlier, or whether it contains useful information, in light of the particular array of ROEs presented by the potential proxy group companies. This is illustrated by the natural break analysis that the Commission performed in both *SoCal Edison*[793] and Opinion No. 531,[794] where the Commission excluded companies whose ROEs were only one and two basis points above the then applicable low-end outlier test, because there was a natural break between those companies' ROEs and the higher ROEs of the companies that the Commission included in the proxy group.

396. We clarify that the Commission will apply such a natural break analysis to both the low-end and high-end outlier tests. We further clarify that the analysis may justify excluding companies whose ROEs are a few basis points above the low-end screen, if their ROEs are far lower than other companies in the proxy group; a similar analysis could also apply with respect to the high-end outlier test. We also clarify that the natural break analysis may justify inclusion of companies in the proxy group despite their failing either the low or high-end outlier test. For instance, a company's ROE could be 152 percent of the median ROE, but, based on this analysis, the Commission may include it in the proxy group if it were not substantially higher than other companies in the proxy group.

397. Further, the Commission has not enumerated a rigid formula, such as specifying how close the company has to be to the next proxy group member to justify inclusion or exclusion from the proxy group, for the application of the natural break analysis, and we decline to do so here. The natural break analysis provides the Commission flexibility to reach a reasonable result based upon the particular array of ROEs presented in a specific case. Although we recognize the value of transparency and predictability, given the number of potential scenarios with respect to outlier proxy group companies, we are not convinced that there is any specific formula that would reach reasonable results in every possible factual situation. In any event, we believe it is appropriate to develop our policy on this issue through case-by-case analysis, rather than adopting a specific formula here.

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[793] 131 FERC ¶ 61,020 at P 56.

[794] 147 FERC ¶ 61,234 at P 123.

XI. Use of Midpoint or Median as Measure of Central Tendency

398. In determining the central tendency of the zone of reasonableness, the Commission has distinguished between cases involving an RTO-wide ROE and cases involving the ROE of a single utility (or pipeline). In cases involving an RTO-wide ROE, the Commission has held that the midpoint is appropriate. The Commission has reasoned that, because an RTO-wide ROE will apply to a diverse set of companies, the range of results becomes as important as the central value, and the midpoint fully considers that range, because it is derived directly from the endpoints of the range. The Commission established this policy in an order on remand in the proceeding establishing the MISO TOs' 12.38 percent ROE.[795] By contrast, in cases involving a single utility, the Commission has held that using the median is appropriate, because the median "is the most accurate measure of central tendency for a single utility of average risk."[796] In the Briefing Order, the Commission proposed to continue this policy.[797]

399. As described below, the CAPs and OMS assert that the Commission should no longer use the midpoint in cases involving an RTO-wide ROE, while MISO TOs defend the current policy. As discussed below, the Commission is retaining its current policy of using the midpoint for determining the central tendency of the zone of reasonableness in cases involving an RTO-wide ROE.

A. CAPs

400. CAPs recommend using the median for setting the base ROE for all MISO TOs, noting that the Commission has found that the "median best represents central tendency" if a distribution is skewed, for companies of average risk.[798] CAPs further assert that "the midpoint is inherently inferior to the median as a measure of central tendency because it depends upon only the two most extreme, unrepresentative observations . . . and ignores

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[795] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at PP 9-10 (2004) (*MISO Remand Order*), *aff'd*, *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005) (*Pub. Serv. Comm'n of Ky. v. FERC*).

[796] *See SoCal Edison*, 131 FERC ¶ 61,020, at P 91, *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013) (*S. Cal. Edison v. FERC*).

[797] Briefing Order, 165 FERC ¶ 61,118 at P18 n.40.

[798] CAPs Initial Br. (I) at 54; CAPs Initial Br. (II) at 53.

the distribution of proxy group results."[799] CAPs contend that the midpoint may be higher than almost all data points in a given distribution, and using the midpoint of such a distribution to establish a base ROE has previously been found arbitrary and capricious.[800]

401. CAPs acknowledge that the Commission previously found in the *MISO Remand Order* that using the midpoint to determine a single ROE for a diverse group of utilities is justified. However, CAPs contend that the *MISO Remand Order* is distinguishable from this proceeding. They contend that the *MISO Remand Order* emphasized that the proxy group used to define the zone of reasonableness in that proceeding was a subset of the MISO TOs to which the ROE would apply. Therefore, the Commission stated that, unlike a case involving a single utility, it was "not as concerned that the high or low results represent different risks from the single company because the range encompasses only publicly traded Midwest ISO TOs. Rather, we must use the measure that produces the most just and reasonable ROE for all of the Midwest ISO TOs."[801]

402. CAPs point out that here, unlike in the *MISO Remand Order*, the zone of reasonableness is based on a national proxy group. They assert that the "risk comparability requirement established in *Bluefield* emphasizes the geographic proximity of proxy companies." However, CAPs state that most of the proxy group companies are national holding companies whose risk profiles include risk unrelated to the MISO TOs' transmission risk, and as a result, the range of costs of equity for this group are fundamentally not comparable to those of the MISO TOs.[802] In particular, CAPs note that the credit ratings for the high and low-end outliers of the national proxy group do not correspond to those of the MISO TOs.[803] Furthermore, CAPs claim that the proxy group companies have, on average, worse credit ratings than the MISO TOs.[804]

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[799] CAPs Initial Br. (I) at 40 (citing Ex. OMS-108 at P 4); CAPs Initial Br. (II) at 60-61 (citing Ex. OMS-208 at P 4).

[800] CAPs Initial Br. (I) at 42; CAPs Initial Br. (II) at 63.

[801] CAPs Initial Br. (I) at 54-55 (citing *MISO Remand Order*, 106 FERC ¶ 61,302 at P 10); CAPs Initial Br. (II) at 54.

[802] CAPs Initial Br. (I) at 55; CAPs Initial Br. (II) at 55.

[803] CAPs Initial Br. (I) at 56; CAPs Initial Br. (II) at 55.

[804] CAPs Initial Br. (I) at 57 (citing Ex. OMS-100 at 11); CAPs Initial Br. (II) at 57 (citing Ex. OMS-200 at 11, Ex. OMS-205 at 1-4).

403. Finally, CAPs argue that the justifications for using the midpoint established in previous proceedings are not applicable here. CAPs point out that the MISO Remand Order stated that the MISO TOs are a "broad group of utilities with diverse risks and business profiles," but the Briefing Order stated that the MISO TOs are of average risk.[805] CAPs contend that, if the MISO TOs as a group can be considered of average risk, then using the median, which emphasizes the central tendency of the range, rather than the midpoint, which emphasizes the impact of the outliers, is consistent with Commission precedent.[806] CAPs also note that averaging the midpoints of the DCF range, CAPM range, Expected Earnings range, and Risk Premium singular value to determine a replacement ROE does not consider whether the outliers' risk profiles for each range are comparable to those of the MISO TOs' outliers. As a result, the replacement ROE "may not correspond to [the costs of equity] of the MISO TOs' outliers."[807]

B. MISO TOs

404. MISO TOs state that CAPs' argument for use of the median relied on Commission decisions addressing single-utility ROEs, which ignores the Commission's repeated rulings that the median is an appropriate measure for single-utility ROEs, but the midpoint is the appropriate measure for diverse groups of utilities in ISOs/RTOs.[808] MISO TOs state that the goal of setting a base ROE for an individual utility is to reflect most accurately the risk of an individual utility applicant, while the goal of setting a base ROE for a regional group of utilities is to estimate a central tendency while also reflecting the diverse nature of the group. MISO TOs argue that, when setting the base ROE for a regional group of utilities, the Commission is not seeking the most refined measure of central tendency, but to consider the full range and risks and business profiles, which is why it would be more appropriate to use the approach of using the midpoint for regional groups.[809]

405. MISO TOs state that CAPs' argument that the Commission's use of a national proxy group warrants the abandonment of the midpoint in favor of the median because

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[805] CAPs Initial Br. (I) at 58 (citing *MISO Order Remand Order*, 106 FERC ¶ 61,302 at P 9).

[806] *Id.*; CAPs Reply Br. (I) at 41; CAPs Initial Br. (II) at 58; CAPs Reply Br. (II) at 61.

[807] CAPs Initial Br. (I) at 58-59; CAPs Initial Br. (II) at 58-59.

[808] MISO TOs Reply Br. (I) at 73; MISO TOs Reply Br. (II) at 70-71.

[809] MISO TOs Reply Br. (I) at 73-74; MISO TOs Reply Br. (II) at 71-72.

the returns identified for outliers have no particular correspondence to the highest and lowest risk profiles is inaccurate. MISO TOs state that Opinion No. 531 recognizes that transmission utilities compete nationally for investors' capital, making the national range of utility returns the most appropriate range from which to derive a just and reasonable base ROE.[810]

406. MISO TOs state that the Commission should reject CAPs' argument that the midpoint would overstate MISO TOs' costs of equity and ignore the distribution of the proxy companies' cost of capital estimates. MISO TOs state that CAPs' argument assumes that the midpoint will generally be higher than the median. However, MISO TOs state that nothing about the midpoint ensures that it will be higher than the median in any particular instance and it is only "pure happenstance" when the midpoint exceeds a median of the same range and vice-versa.[811] MISO TOs state that the Commission should reject CAPs' argument for use of the median instead of the midpoint, and that the midpoints of the CAPM and Expected Earning ranges are the appropriate measure of the central tendency.[812]

407. MISO TOs state that, while CAPs argue that the use of the midpoint is no longer appropriate in light of the Commission's adoption of a hybrid method for estimating the cost of equity, the new approach incorporates two new range-producing methods: CAPM and Expected Earnings. MISO TOs argue that the proxy groups for these methods are composed the same way as they have historically been used in the Commission's DCF approach.[813]

408. MISO TOs state that the Commission's proposal for calculating a new base ROE by averaging the four methods is appropriate because the new base ROE will then be a product of the midpoints of the three range-producing methods and the single result of the Risk Premium approach, and disagrees with CAPs' assertion that the Commission's proposed four-method approach would be calculated without regard to its placement within the new composite zone of reasonableness.[814]

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[810] MISO TOs Reply Br. (I) at 74; MISO TOs Reply Br. (II) at 73-74.

[811] MISO TOs Initial Br. (I) at 76 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 186).

[812] MISO TOs Reply Br. (I) at 75; MISO TOs Reply Br. (II) at 75.

[813] MISO TOs Reply Br. (I) at 76; MISO TOs Reply Br. (II) at 75-76.

[814] MISO TOs Reply Br. (I) at 77; MISO TOs Reply Br. (II) at 76.

C. Commission Determination

409. We will continue to use the midpoint to determine the central tendency of the zone of reasonableness in cases involving an RTO-wide ROE, consistent with the policy set forth in the *MISO Remand Order*. The United States Court of Appeals for the District of Columbia upheld that policy in *Public Service Commission of Kentucky v. FERC*. We find that the CAPs have not presented a compelling reason why that policy should not be applied in this case.

410. The court described the *MISO Remand Order's* rationale for using the midpoint in cases involving an RTO-wide ROE as follows,

> The Commission . . . distinguished between 'cases in which a ROE is set for one gas pipeline or electric utility' and cases where 'applicants proposed setting a single ROE for across-the-board application.' In the latter situation, where 'the ROE will apply to a diverse set of companies,' FERC reasoned that the range of results becomes as important as the central value. The midpoint—unlike the other measures of central tendency—'fully considers that range,' because it is derived directly from the endpoints of the range.[815]

411. This reasoning applies equally in this case. The MISO TOs continue to be "a diverse set of companies." For example, in both the First Complaint and Second Complaint proceedings, the MISO TOs' S&P corporate ratings range from BB- to AA, and their Moody's long-term ratings range from Ba3 to Aa2.[816] This broad range of credit ratings supports a finding that the MISO TOs are a diverse group with a variety of risk profiles, even though we treat the group as a whole as of average risk, consistent with the *MISO Remand Order*.[817]

412. We recognize that the proxy group at issue in the *MISO Remand Order* was limited to MISO TOs, whereas in the First Complaint and Second Complaint proceedings we are using national proxy groups that include some firms with no MISO TO operating companies. However, this does not mean that the high and low ends of the DCF and CAPM zones of reasonableness produced by those proxy groups are unrepresentative of the highest and lowest risk profiles among the MISO TOs. In the First Complaint

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[815] *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d at 1010.

[816] Ex. MTO-26 at 2. Ex. MTO-32 at 2.

[817] Cross-Answering Testimony of Ellen Lapson in MISO I, Ex. MTO-39 at 46.

proceeding, the high end of the DCF zone of reasonableness is set by TECO.[818] Its S&P corporate rating is BBB+ and its Moody's long-term rating is Baa1.[819] The high-end of the CAPM zone of reasonableness is set by Black Hills Corp.[820] Its S&P corporate rating is BBB and its Moody's long-term rating is Baa1.[821] Thus, the credit ratings of the two companies whose ROEs are averaged together to establish the high end of the composite zone of reasonableness are both within the MISO TOs' S&P corporate ratings range of BB- to AA, and Moody's long-term ratings range of Ba3 to Aa2. The low end of the DCF range of reasonableness is set by Public Service Enterprise Group and IDACORP, Inc.[822] Public Service Enterprise Group's S&P corporate rating is BBB+ and its Moody's long-term rating is Baa2.[823] IDACORP, Inc.'s S&P corporate rating is BBB and its Moody's long-term rating is Baa1.[824] The low-end of the CAPM zone of reasonableness is set by Duke Energy Corp. (Duke) and Southern Company (Southern).[825] Duke's S&P corporate rating is A- and its Moody's long-term rating is A3.[826] Southern's S&P corporate rating is A, and its Moody's long-term rating is Baa1.[827] These credit ratings are also within the ranges of MISO TOs' S&P corporate ratings and Moody's long-term ratings range.[828] Thus, the companies that set the high and low ends of the DCF and CAPM zones of reasonableness in the First Complaint proceeding have similar risk

[818] *See* Appendix A to this order.

[819] Ex. MTO-26 at 1.

[820] *See* Trial Staff Initial Br. (I), Attachment A to App. 2 at 6, which, as discussed in section XVI of this order, reflects our holdings concerning the appropriate CAPM analysis for the First Complaint proceeding.

[821] Ex. MTO-26 at 1.

[822] Appendix A.

[823] Ex. MTO-26 at 1.

[824] *Id.*

[825] Trial Staff Initial Br. (I), Attachment A to App. 2 at 6. In addition, Duke owns Duke Energy Indiana, Inc., a member of MISO.

[826] Ex. MTO-26 at 1.

[827] *Id.*

[828] *Id.*

profiles to the MISO TOs, and one of those companies is in fact a member of MISO. Similarly, in the Second Complaint proceeding, the high end of the DCF zone of reasonableness is set by PNM Resources.[829] Its S&P corporate rating is BBB+ and its Moody's long-term rating is Baa3.[830] The high-end of the CAPM zone of reasonableness is set by Otter Tail Corp. (Otter Tail).[831] Its S&P corporate rating is BBB and its Moody's long-term rating is Baa2.[832] These credit ratings are both within the MISO TOs' S&P corporate ratings range of BB- to AA, and Moody's long-term ratings range of Ba3 to Aa2. The low end of the DCF zone of reasonableness is set by CenterPoint Energy, Inc.[833] Its S&P corporate rating is A- and its Moody's long-term rating is Baa1.[834] The low-end of the CAPM zone of reasonableness is set by PG&E.[835] Its S&P corporate rating is BBB and its Moody's long-term rating is Baa1.[836] These credit ratings are also within the ranges of MISO TOs' S&P corporate ratings and Moody's long-term ratings. Thus, the companies that set the high and low ends of the DCF and CAPM zones of reasonableness in the Second Complaint proceeding also have similar risk profiles to the MISO TOs, and one of those companies is in fact a member of MISO.

413. We also disagree that the Commission should abandon the midpoint in favor of the median because the proxy group ROEs could be so skewed that the midpoint might be higher than almost all the proxy group ROEs. As the Commission recognized in the MISO Remand Order, the midpoint may be inappropriate in certain circumstances because of egregious distortion by the highest or lowest number. However, here the proxy group ROEs are not so skewed as to render the midpoint inappropriate. In the First Complaint proceeding, the 9.88 percent midpoint of composite zone of reasonableness is only 38 basis points, or four percent, above the 9.50 percent median. In the Second

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[829] *See* Appendix B to this order.

[830] Ex. MTO-32 at 1.

[831] *See* Trial Staff Initial Br. (II), Attachment A to App. 2 at 6, which, as discussed in section XVII of this order, reflects our holdings concerning the appropriate CAPM analysis for the Second Complaint proceeding. Otter Tail is also a member of MISO.

[832] Ex. MTO-32 at 1.

[833] Appendix B.

[834] Ex. MTO-32 at 1.

[835] Trial Staff Initial Br. (I), Attachment A to App. 2 at 6.

[836] Ex. MTO-32 at 1.

Complaint proceeding, the 9.72 percent midpoint of the composite zone of reasonableness is only 4 basis points, or less than one percent, above the 9.68 percent median. The proxy group ROEs in these cases are thus no more skewed than in the *Pub. Serv. Comm'n of Ky. v. FERC* case, where the 12.38 percent midpoint of the zone of reasonableness was 53 basis points, or about 4.5 percent, above the 11.85 percent median. In that case, the court recognized that, although there was some skew, "this is part of the reason FERC used the midpoint in the first place."[837] The same reasoning applies to the current cases.

414. Accordingly, we will determine the central tendency of both the DCF and CAPM zones of reasonableness in the First Complaint and Second Complaint proceedings based on the midpoint, consistent with our policy of using the midpoint in cases involving RTO-wide ROEs.

XII. Weighting of Models

A. Background

415. In the Briefing Order, the Commission proposed to use the DCF model, the CAPM, and the Expected Earnings model to determine whether an existing ROE remains just and reasonable under the first prong of FPA section 206.[838] The Commission then proposed to use the DCF model, the CAPM, the Expected Earnings model, and the Risk Premium model for establishing a new just and reasonable ROE, where the existing ROE has been shown to be unjust and unreasonable (i.e., the second prong of the FPA section 206 analysis).[839] Under each prong, the Commission proposed to give the models to be used equal weight.[840] Below, we discuss issues raised by the participants with respect to the weighting of the various proposed models.

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[837] *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F. 3d at 1003.

[838] Briefing Order, 165 FERC ¶ 61,118 at P 17.

[839] *Id.* P 18.

[840] *See id.* PP 13, 16, 18, 32.

B. CAPs

416. CAPs argue that the Expected Earnings model should be excluded and, if included, should be given the least amount of weight.[841] As described above, CAPs assert that the Expected Earnings model does not accurately estimate a utility's cost of equity, because it is an accounting-based measure that does not reflect the rate of return that investors require in the market-priced common equity capital of a utility.[842] CAPs argue that there is no evidence investors give the Expected Earnings model any weight in informing their investment decisions.[843] If used, CAPs contend that the Expected Earnings model should be weighted significantly less than the market-oriented models (suggested weight of 16.7 percent for prong one and 12.5 percent for prong two),[844] arguing that it distorts and inflates the estimate of investors' required return on market-priced equity.[845]

417. CAPs also assert a number of reasons why the DCF should be weighted more than other models. First, CAPs argue that the Commission has used the DCF method for many years with proven success.[846] Second, CAPs state that, in contrast to other proposed models, the Commission has refined and honed the DCF model over a number of years, making it more accurate.[847] Third, CAPs contend that, because the Commission has used the DCF model for many years, investors are familiar with it and more likely to

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[841] CAPs Initial Br. (I) at 46; CAPs Initial Br. (II) at 46; CAPs Reply Br. (I) at 40, 46; CAPs Reply Br. (II) at 60, 67.

[842] CAPs Initial Br. (I) at 40-44; CAPs Initial Br. (II) at 39-44. CAPs states that the Expected Earnings model may only help predict the stock-issuing company's own rate of return per *its* book equity, not the investor's own rate of return on investment unless adjusted for the market/book ratio. CAPs Reply Br. (I) at 47; CAPs Reply Br. (II) at 67.

[843] CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 67.

[844] CAPs Initial Br. (I) at 47; CAPs Initial Br. (II) at 47; Ex. OMS-108 at 8-9; Ex. OMS-208 at 8.

[845] CAPs Initial Br. (I) at 46; CAPs Initial Br. (II) at 46.

[846] CAPs Initial Br. (I) at 46; CAPs Initial Br. (II) at 46; CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 66.

[847] CAPs Initial Br. (I) at 46; CAPs Initial Br. (II) at 46; CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 66-67.

apply it in the same manner as prescribed the Commission.[848] Fourth, CAPs argue that the DCF model is a superior model for assessing investors' expectations and required returns, because it is the only one that incorporates direct inputs from investors pertaining to the market value of electric utilities' common equity capital (through the "P" term in the DCF equation).[849]

418. CAPs argue that the Commission should exclude the Expected Earnings model, and if it is excluded, that the Commission should use the following weighting for the different models. CAPs assert that for the prong one analysis, the Commission should weight the DCF model at 60 percent and the CAPM at 40 percent; and that for the prong two analysis, the Commission should weight the DCF model at 42.8 percent, the CAPM at 28.6 percent, and the Risk Premium model at 28.6 percent.[850] CAPs contend that, if the Commission includes the Expected Earnings model, the Commission should use the following weighting for the different models. CAPs assert that for prong one, the Commission should weight the DCF model at 50 percent, the CAPM at 33.3 percent, and the Expected Earnings model at 16.7 percent; and that for the prong two analysis, the Commission should weight the DCF model at 37.5 percent, the CAPM at 25 percent, the Expected Earnings model at 12.5 percent, and the Risk Premium model at 25 percent.[851]

C. MISO TOs

419. MISO TOs assert that CAPs' argument to weight the DCF model more heavily than other models is arbitrary and unsupported by evidence.[852] MISO TOs argue in support of weighting all models equally. MISO TOs argue that the methodology is complex as is and that unequal weighting would only result in an extra layer of subjectivity.[853]

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[848] CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 67.

[849] CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 67.

[850] CAPs Initial Br. (I) at 47-48; CAPs Initial Br. (II) at 46-47; Ex. OMS-100 at 7-8; Ex. OMS-200 at 7-8.

[851] CAPs Initial Br. (I) at 47-48; CAPs Initial Br. (II) at 46-47; Ex. OMS-100 at 7-8; Ex. OMS-200 at 7-8.

[852] MISO TOs Reply Br. (I) at 52; MISO TOs Reply Br. (II) at 51.

[853] MISO TOs Reply Br. (I) at 52; MISO TOs Reply Br. (II) at 51.

420. MISO TOs contend that because there is no evidence that one model is inherently superior to another, weighting them differently is an option unsupported by evidence.[854] MISO TOs argue the Commission has recognized that there is no single approach that is fundamentally superior or foolproof and that each model offers unique features with their own advantages and disadvantages.[855]

421. While MISO TOs generally support weighting all models equally, MISO TOs take particular exception to giving the DCF more weight as compared to other models.[856] MISO TOs state that the evidence submitted during this proceeding indicates that the DCF model fails to meet the *Hope* and *Bluefield* standards, and, therefore, CAPs' argument to weight the DCF model more than the others is particularly flawed.[857]

D. Trial Staff

422. Trial Staff acknowledges that the Commission has proposed to use equal weighting for all models.[858] Trial Staff argues that the Commission should not use the Expected Earnings model for either prong.[859] But if the Commission chooses to use the Expected Earnings model, Trial Staff proposes that, for prong one, the Commission should weight the DCF model, the CAPM, and the Expected Earnings model equally.[860] Additionally, for prong two, Trial Staff proposes that the Commission should weight the

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[854] MISO TOs Reply Br. (I) at 52; MISO TOs Reply Br. (II) at 51-52.

[855] MISO TOs Reply Br. (I) at 52-53; MISO TOs Reply Br. (II) at 51-52.

[856] MISO TOs Reply Br. (I) at 53; MISO TOs Reply Br. (II) at 51-52. MISO TOs also assert there is evidence that investors' decisions are more closely aligned with factors relating to CAPM than other models. MISO TOs argue that this further cuts against CAPs' proposal to rely more heavily on the DCF model. MISO TOs Reply Br. (I) at 53 n.212 (citing Jonathan B. Berk & Jules H. van Binsbergen, *How Do Investors Compute the Discount Rate? They Use the CAPM,* Fin. Analyst J. (2d. Quarter 2017)); MISO TOs Reply Br. (II) at 52 (citing same).

[857] MISO TOs Reply Br. (I) at 53; MISO TOs Reply Br. (II) at 51-52.

[858] Trial Staff Initial Br. (I) at 20; *see* Trial Staff Initial Br. (II) at 18-19.

[859] Trial Staff Initial Br. (I) at 6; Trial Staff Initial Br. (II) at 5.

[860] Trial Staff Initial Br. (I), Keyton Aff. (I) at 39; Trial Staff Initial Br. (II), Keyton Aff. (II) at 37.

DCF model, the CAPM, the Risk Premium model, and the Expected Earnings model equally.[861]

E. RPGI

423. RPGI argues that the Commission should weight the DCF model no less than one-half in proportion to the other models.[862] RPGI states that the Commission has not explained nor justified no longer relying exclusively on the DCF model, rather than utilizing an equally-weighted multiple methodology approach.[863] RPGI argues that, because the Commission has previously observed that the DCF model is statistically superior to alternatives and the Commission has not provided any evidence that the alternative models produce better forecasts, the DCF model should not be weighted equally with the others.[864] RPGI summarizes its arguments in support of the DCF model being weighted at one-half, at the least, by stating that the DCF methodology maintains a preferred status at the Commission and that the Commission has failed to adequately explain its reasoning for adopting a changed course of action.[865]

F. Commission Determination

424. As discussed above in sections VI and VIII, we find that is not appropriate to use the Expected Earnings and Risk Premium models in ROE methodology. Accordingly, the Commission will not give those models any weight in the analysis under either prong one or prong two of FPA section 206. As a result, the arguments proposing alternative weighting of the various models if the Expected Earnings and Risk Premium models are included in the ROE methodology are moot and we will not address them here.

425. In light of our decision not to use the Expected Earnings and Risk Premium models, we will apply only the DCF and CAPM models, giving equal weight to each model. Specifically, the top and bottom of the zones of reasonableness produced by the DCF and CAPM will be given equal weight and averaged to produce a single composite zone of reasonableness that will be used for both the prong one and prong two analysis

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[861] Trial Staff Initial Br. (I), Keyton Aff. (I) at 51; Trial Staff Initial Br. (II), Keyton Aff. (II) at 49.

[862] RPGI Initial Br. (I) at 5, 38; RPGI Initial Br. (II) at 4, 41.

[863] RPGI Initial Br. (I) at 11; RPGI Initial Br. (II) at 15-16.

[864] RPGI Initial Br. (I) at 16, 25; RPGI Initial Br. (II) at 20, 29.

[865] RPGI Initial Br. (I) at 38; RPGI Initial Br. (II) at 41.

under FPA section 206. As discussed in section IV above, in order to determine whether an existing ROE is unjust and unreasonable, we will divide the composite zone of reasonableness into quartiles; the quartile centered on the central tendency[866] of the overall composite zone of reasonableness will represent the range of presumptively just and reasonable ROEs for average risk utilities, and the quartiles centered on the central tendencies of the upper and lower halves of the composite zone of reasonableness will represent the range of presumptively just and reasonable ROEs for above- and below-average utilities, respectively. For purposes of determining just and reasonable ROEs under the second prong of FPA section 206 (and under FPA section 205), we will generally set the ROE of average risk utilities at the central tendency of the overall composite zone of reasonableness, and set the ROEs of above average risk utilities at the central tendency of the upper half of the composite zone of reasonableness and below average risk utilities at the central tendency of the lower half of the composite zone of reasonableness.[867]

426. We find that the record evidence supports giving each model that will be used in the ROE methodology equal weight, as described above. The evidence indicates that neither remaining model is conclusively superior to the other model. Each model has unique aspects, and advantages and disadvantages that make it preferable to the other model in some respects, but not other respects. Parties point out, for example, that the DCF model is the only one that incorporates direct inputs from investors pertaining to the market value of electric utilities' common equity capital;[868] however, parties also argue that investors base their decisions on factors more closely aligned with those contained within the CAPM.[869] Accordingly, we find that, on balance, the evidence does not indicate that there is a clearly superior model for estimating cost of equity that should be given more weight than the others. Moreover, we find that equally weighting the two models will reduce the model risk associated with any particular model more than giving one model greater weight than the other. Therefore we find that the risks associated with

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[866] As noted above in section XI, the Commission will continue to use the midpoint of the zone of reasonableness as the appropriate measure of central tendency for a diverse group of average risk utilities and the median as the measure of central tendency for a single utility.

[867] We do not intend by this discussion to foreclose the possibility that a particular utility could be of such high or low risk to justify setting its ROE at the top or bottom of the composite zone of reasonableness.

[868] CAPs Reply Br. (I) at 46; CAPs Reply Br. (II) at 67.

[869] MISO TOs Reply Br. (I) at 53 n.212 (citing Jonathan B. Berk & Jules H. van Binsbergen, *How Do Investors Compute the Discount Rate? They Use the CAPM,* Fin. Analyst J. (2d. Quarter 2017)); MISO TOs Reply Br. (II) at 52 (citing same).

the potential errors or flaws in any one model will be mitigated to the greatest extent by giving each model equal weight.

427. Accordingly, we give equal weight to the CAPM and DCF models for purposes of the analysis under both prong one and two of the FPA, as discussed above.

XIII. Sequencing of Calculations in Determining Composite Zone

A. Background

428. As proposed in the Briefing Order, the calculations for determining the composite zone of reasonableness and applicable range of presumptively just and reasonable ROEs under the first prong of section 206 would be carried out as follows. First, a proxy group would be determined for each model using existing Commission screens. Second, for each model, low and high end outliers would be removed using applicable tests. Third, the models would apply to the proxy groups for each model, which would produce separate zones of reasonableness from each model. Fourth, the top and bottom of the zone of reasonableness produced by each methodology would be averaged to determine a single composite zone of reasonableness. Fifth, the midpoint/median, lower midpoint/median, and upper midpoint/median of that composite zone would be calculated. Sixth, the quartile ranges constituting the ranges of presumptively just and reasonable ROEs would be calculated, with the average risk quartile centered on the midpoint/median of the composite range, the above-average risk quartile centered on the upper midpoint/median of the composite range, and the below-average risk quartile is centered on the lower midpoint/median of the composite range. The Commission would then determine whether the utility, or group of utilities, at issue are of average risk, above-average in risk, or below-average in risk as compared with the proxy companies in order to determine the applicable range of presumptively just and reasonable ROEs. The Commission would then consider any other record evidence that would be relevant to its determination under the first prong of section 206.

429. As proposed in the Briefing Order, if an existing ROE is found to be unjust and unreasonable under the first prong of section 206, then the additional calculations necessary to determine a replacement just and reasonable ROE would be carried out as follows. First, the applicable midpoint/median, or upper or lower midpoint/median, within the zones of reasonableness would be identified for the utility or utilities. Then those applicable midpoint/medians (or upper or lower midpoint/medians) would be given equal weight and averaged to produce a replacement ROE. As proposed in the Briefing Order, the cost of equity estimate produced by the Risk Premium model would also be given equal weight and averaged with the other values. However, as discussed above in section VIII, we find that it is not appropriate to include the Risk Premium model in our ROE methodology. Therefore that part of the calculation will not be included and we need not address it here.

B. CAPs

430. CAPs argue that the Commission should use only the DCF model, but that, if the Commission instead uses multiple financial models, the Commission should use a different sequence of calculations to determine the composite zone of reasonableness and replacement ROE than the sequence proposed in the Briefing Order.[870] CAPs argue that the computational sequence proposed in the Briefing Order increases the potential for errors due to model risk because it treats each model's range as a separate zone of reasonableness, which results in separate results (median or midpoint) that are then averaged to establish the replacement ROE, but each model's median or midpoint carries its own margin of error. CAPs contend that a more appropriate computational sequence is to average the results of each proxy company's DCF and CAPM values, after first addressing any low-end or high-end outliers associated with each methodology.[871]

431. In particular, CAPs' witness, Dr. Berry, proposes to first calculate for each proxy company the average[872] of the DCF and the CAPM results to determine a company-specific cost of equity. Specifically, Dr. Berry proposes to modify the sequence of calculations proposed in the Briefing Order for determining the composite zone of reasonableness and applicable range of presumptively just and reasonable ROEs under the first prong of section 206 to be carried out as follows. First, a proxy group would be determined using existing Commission screens. Second, for each model, low and high end outliers would be removed using applicable tests. Third, a cost of equity *for each proxy group company* would be determined by averaging the DCF and the CAPM results for each company. Fourth, highest and the lowest company-specific composite costs of equity would define the upper bound and the lower bound of the composite zone of reasonableness. Fifth, the Commission would determine whether the utility or utilities are of average risk, above-average risk, or below-average risk as compared with the proxy companies.[873]

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[870] CAPs Initial Br. (I) at 65-66, Ex. OMS-100 at 9, Ex. OMS-108 at 9; CAPs Initial Br. (II) at 65-66, Ex. OMS-200 at 9, Ex. OMS-208 at 9.

[871] CAPs Initial Br. (I) at 65-66; CAPs Initial Br. (II) at 65-66.

[872] We note that Dr. Berry proposes to use a weighted average in calculations based on his proposed alternative weighting of the different models. As discussed above in section XII, we are not adopting Dr. Berry's proposed alternative weighting therefore we need not address that aspect of his proposal in this section.

[873] CAPs Initial Br. (I), Ex. OMS-100 at 10-11; CAPs Initial Br. (I), Ex. OMS-200 at 10-11.

432. Under Dr. Berry's proposal, if an existing ROE is found to be unjust and unreasonable then the applicable median, or upper or lower median, of the composite zone would then be averaged with the Risk Premium model result to calculate a just and reasonable replacement ROE.[874]

433. CAPs provide several reasons in support of this alternative sequencing approach. First, CAPs assert that there is only one just and reasonable return for a given proxy company, though it is not directly observable, and the DCF and the CAPM methods attempt to estimate this unknown cost of equity for each proxy company. CAPs argue that, therefore, the identification of each proxy's equity cost is improved if both methods are combined in identifying *that proxy's* single equity cost.[875] Second, CAPs contend that upper bounds, lower bounds, and midpoints/medians produced by each separate model are susceptible to model risk because they are calculated using only one model. Third, CAPs argue that this alternative sequencing approach reduces model risk by more effectively limiting the inclusion of extreme results in the proxy groups.[876] To illustrate this point, CAPs state that other parties, by implementing the traditional sequencing approach, have engaged in blatant cherry-picking, as evidenced by the fact that each model's proxy groups yielded a different company as the high point.[877] Third, in response to MISO TOs' argument that this alternative sequencing approach washes out the limits of the respective ranges of risk from independent financial models, CAPs argue that the narrowing of the composite zone of reasonableness is appropriate because it enhances the precision of the estimates and excludes the extreme and unrepresentative values that would otherwise be given undue and unreasonable weight.[878] Fourth, CAPs state that any instance where companies may get weighted more or less, simply because they have more or less available financial data, would occur all the same using the traditional sequencing approach.[879] Fifth, CAPs argue that using the alternative

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[874] CAPs Initial Br. (I), Ex. OMS-100 at 11; CAPs Initial Br. (I), Ex. OMS-200 at 11.

[875] CAPs Initial Br. (I), Ex. OMS-100 at 12; Ex. OMS-108 at 9-10; CAPs Initial Br. (II), Ex. OMS-200 at 11-12; Ex. OMS-208 at 9.

[876] Ex. OMS-100 at 13; Ex. OMS-108 at 10; Ex. OMS-200 at 13; Ex. OMS-208 at 10.

[877] Ex. OMS-108 at 10; Ex. OMS-208 at 10.

[878] Ex. OMS-108 at 11; Ex. OMS-208 at 11.

[879] Ex. OMS-108 at 11; Ex. OMS-208 at 11.

sequencing approach to control for outliers leads to results not materially different from the traditional approach.[880]

C. MISO TOs

434. MISO TOs argue that, rather than averaging the cost of equity estimates produced for each individual proxy company across the DCF model and the CAPM, as CAPs support, a separate range and midpoint should be produced for each model as proposed in the Briefing Order.[881] MISO TOs state that the ultimate goal is to specify the broad range of potentially lawful ROEs, and argue that their proposal for a traditional sequencing approach meets that standard.[882]

435. MISO TOs state a number of supporting arguments to claim that CAPs' proposed alternative sequencing approach does not meet this ultimate goal. First, MISO TOs argue that evaluations of the cost of equity typically present the results of alternative models independently, rather than averaging estimates for each individual firm in a proxy group under the separate models.[883] MISO TOs claim that no witnesses for the complainants had previously presented their methodology in this way and that no examples of similar proposals in comparable regulatory proceedings has been presented.[884]

436. Second, MISO TOs state that it is important to compare the results of each methodology against the others, and that, if the Commission followed CAPs' suggested approach, this comparison would be obscured due to a reduction of the results to a single, arithmetic average.[885] Third, MISO TOs argue that CAPs' approach, based on the arithmetic mean of the cost of equity estimates for each proxy company, contradicts the

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[880] Ex. OMS-108 at 12; Ex. OMS-208 at 11.

[881] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (II) at 112; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 112.

[882] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 112; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 112.

[883] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 114; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 114.

[884] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 114-15; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 114-15.

[885] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 113; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 113.

Commission's precedent of using range and midpoint values.[886] Fourth, MISO TOs state that CAPs' approach does not cancel out model risk or address the impact of extreme results, as CAPs claim, but, rather, just narrows the range by muting out the upper-end estimates.[887] Fifth, MISO TOs argue that the purpose of the proceedings is to arrive at a single ROE that fully considers the range of risks for a diverse group of transmission owners; but, MISO TOs claim that CAPs' approach, instead, determines the average ROE for the average utility, which washes out the limits of the respective ranges of risk from independent financial models.[888]

D. Commission Determination

437. We will use the sequence of calculations proposed in the Briefing Order for the analyses under the first prong and second prong of section 206, with revisions to reflect our decision not to use the Expected Earnings or Risk Premium models, as discussed herein. In particular, we will apply the DCF and CAPM models separately to the applicable proxy group, producing two zones of reasonableness: a DCF zone of reasonableness and a CAPM zone of reasonableness. Then the top of the DCF zone of reasonableness will be averaged with the top of the CAPM zone of reasonableness and the bottom of the DCF zone of reasonableness will be averaged with the bottom of the CAPM zone of reasonableness to determine a single composite zone of reasonableness for use in both the first and second prong analysis under FPA section 206. If an existing ROE is found to be unjust and unreasonable, the replacement ROE will be set at the central tendency of the composite zone or reasonableness or the central tendency of the upper or lower halves of the composite zone of reasonableness depending upon whether the utility is of average, above average, or below average risk, respectively.

438. We will not adopt CAPs' proposed alternative calculation sequence. As noted above, CAPs propose that we determine a cost of equity for each proxy group company by averaging the company-specific DCF and the CAPM results for each company and then using those company-specific composite costs of equity to define the composite zone of reasonableness. We find that the record evidence supports that the DCF and

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[886] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 113; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 113.

[887] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 113; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 113. MISO TOs point out that a standard outlier test would address OMS's concerns about extreme cost of equity estimates. MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 113 n.266; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II) at 113 n.266.

[888] MISO TOs Reply Br. (I) App. 2, McKenzie Reply Aff. (I) at 114; MISO TOs Reply Br. (II) App. 2, McKenzie Reply Aff. (II)at 114.

CAPM models that we will use are intended to produce results separately based on the entire applicable proxy group to which the model is applied, without computing averages across multiple methods for a single company, as CAPs propose. There is no record evidence indicating that analysts apply these models in this way or present the results of these models in this way, nor has any party provided an example of these models being applied this way in a comparable regulatory proceeding. There is also nothing in the record to indicate that the assumptions or structures of the DCF and CAPM models contemplate that the result for a specific proxy group company will be isolated and averaged with a company-specific result from a separate model, rather than considered along with the full range of returns for the entire proxy group that the models produce. The sequencing approach that we adopt here allows the models to function as they are designed until they produce their intended end result. CAPs' alternative proposal would interfere in the function of the models before they produce their intended end result and instead take inputs from the models and combine them before the inputs were used as the models intended.

439. Moreover, the purpose of the DCF and CAPM models is to produce a range of returns applicable to the entire span of investment risks for a proxy group of utilities. The purpose is not to provide a specific cost of equity estimate for each proxy group company that can be considered in isolation, outside of the parameters of the model, and then averaged with a company-specific estimate from a separate model. The product of each model is the full range of cost of equity estimates, as calculated within the parameters of the model. There is no evidence to indicate that the DCF and CAPM models would produce superior results if we used the individual data points that form each model's range, before looking at the ranges themselves that are the intended product of the models.

XIV. Use of Group-Wide ROEs as Opposed to Individual Utility ROEs

A. Alliant

440. Alliant argues that the Commission's ROE methodology should allow the base ROE of each individual transmission owner to be different from that established for the group of MISO TOs as a whole. Alliant argues that this is appropriate because the cost of equity may be different among individual transmission owners within a designated group based on company-specific risk factors. Alliant acknowledges the potential administrative burden that would be associated with examining each individual transmission owner's circumstances to determine if a specific transmission owner warrants a different ROE and to mitigate this, proposes to allow stakeholders the

opportunity to provide arguments within the already existing proceeding as to why a specific transmission owner warrants further examination.[889]

B. OMS

441. OMS also argues that the Commission should depart from using RTO-wide ROEs and adopt a more granular approach to examining the risk profiles of utilities in future transmission rate proceedings. OMS contends that the rationale for the original RTO-wide ROE was avoiding unnecessary litigation that could jeopardize formation of MISO, and this rationale no longer applies. OMS asserts that an RTO-wide ROE does not result from proxy groups that appropriately reflect the risk-profile of individual transmission owners based on their own credit rating. OMS contends that the record demonstrates that the MISO TOs feature a wide range of risk profiles and that, for example, a utility with an S&P AA credit rating should not have its rate of return determined using a proxy group that includes companies with an S&P BBB- credit rating. OMS argues that this will over-compensate some transmission owners and under-compensate others. OMS acknowledges that proving that the risks faced by an individual transmission owner (among a group of utilities) are higher or lower than those faced by companies in the proxy group through a comparative risk analysis is difficult. However, OMS does not propose a specific alternative approach but only asks the Commission to pursue a more granular risk analysis of individual transmission owners.[890]

C. MISO TOs

442. MISO TOs argue that the proposals by Alliant and OMS to evaluate MISO TOs' on an individual basis rather than a region-wide group are beyond the scope of these proceedings. MISO TOs assert that at no time prior to the Briefing Order did any complainant, intervenor (including Alliant and OMS), or Commission Trial Staff submit evidence or a brief arguing for evaluation of each MISO TOs' base ROEs on an individual basis. MISO TOs also contend that the complaints in these proceedings challenged the MISO TOs' region-wide base ROE and did not seek a new ROE separately for each transmission owner. MISO TOs also assert that the Commission's orders setting the cases for hearing gave no indication that the possibility of company-specific ROEs was at issue. MISO TOs argue that, accordingly, entertaining these proposals at this stage of the proceedings would deny the MISO TOs due process.[891]

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[889] Alliant Initial Br. (I) at 9-10; Alliant Initial Br. (II) at 9-10.

[890] OMS Initial Br. (I) at 2-8; OMS Initial Br. (II) at 2-8.

[891] MISO TOs Reply Br. (I) at 79-81; MISO TOs Reply Br. (II) at 78-80.

D. Commission Determination

443. We find that the Alliant's and OMS's requests to depart from the use of an RTO-wide ROE are outside the scope this proceeding. The complaints that originated these proceedings asserted that the base ROE for MISO TOs was unjust and unreasonable because it was too high. They did not, however, dispute the use of an RTO-wide ROE for the MISO TOs or contend that each MISO TO's base ROE should be different. Moreover, the Commission did not propose to depart from the use of an RTO-wide ROE for the MISO TOs in its orders in Order No. 551 or in the Briefing Order. Consequently, we find that such arguments are beyond the scope here.

444. Still, even in light of this finding, we note that it is appropriate for MISO, consistent with its historical practice,[892] to retain a single RTO-wide base ROE.[893] The reason is that many of the factors that affect the cost of capital for the MISO TOs are similar due to their MISO membership. For example, MISO administers a regional planning process in which the need for transmission upgrades and expansions within the RTO are established and the MISO TOs are subject to the same requirements with respect to construction of and cost responsibility for the upgrades and expansions identified in the that planning process. In particular, we note that MISO TOs share cost responsibility for some transmission facilities developed pursuant to the MISO Transmission Expansion Plan.[894] In addition, all of the MISO transmission facilities are pooled and operated by MISO and subject to MISO's functional control without distinction as to ownership. Accordingly, the risks faced by the MISO TOs associated with the operation of their transmission facilities will be substantially similar because the facilities will share the same operator and the costs associated with that operation will be shared by the MISO TOs as members of MISO. Furthermore, there is a single OATT for the MISO region and therefore the rules and requirements applicable to the use of those facilities will be similar in many ways. We find that in such circumstances it is reasonable to allow the

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[892] *See MISO Remand Order*, 106 FERC ¶ 61,302 at P 9 ("[H]ere the applicants proposed setting a single ROE for . . . application to all but one of the Midwest ISO TOs. Accordingly, . . . we must calculate a single ROE for application to a broad group of utilities with diverse risks and business profiles") .

[893] *See* Opinion No. 551, 156 FERC ¶ 61,234 at P 2 ("The 12.38 percent base ROE continues to be the applicable ROE under Attachment O of the MISO Tariff used by all MISO TOs except for American Transmission Company, LLC (ATC).").

[894] *See, e.g.*, Midcontinent Independent System Operator, Inc., Compliance Filing Reporting on Multi-Value Project Process Under the Open Access Transmission, Energy and Operating Reserve Markets Tariff, Docket No. ER10-1791-000, at Tab A (filed Apr. 23, 2019) (discussing cost-shared projects in MISO and cost allocations).

use of a single RTO-wide ROE because many of the factors influencing the return that investors would require to invest in the MISO TOs are similar such as operating risks, the potential effects of upgrades and expansions, and the rules and requirements applicable to use of their transmission facilities.

445. Moreover, we find that using a single RTO-wide base ROE will likely promote closer integration among the transmission owners in the MISO region and consistency in MISO planning efforts because the effects of RTO planning and expansion decisions will be more balanced across the various different transmission owners with a single RTO-wide ROE than if those transmission owners earned multiple different ROEs on their respective rate bases.

446. Furthermore, even when a single ROE is used for all of the MISO TOs, the method and the calculation of that ROE accounts for differences between the MISO TOs. For example, the comparable risk band used in forming the proxy groups in these proceedings is based on the credit rating range of all of the MISO TOs.[895] Similarly, the Commission considers the full range of the risks and business profiles of the MISO TOs in setting the single RTO-wide ROE. The Commission has explained that, "Given that the ROE will apply across-the-board to all members of the Midwest ISO, rather than to a single company of average risk, we must consider their full range of risks and business profiles."[896] In addressing the MISO TOs' ROE, the Commission similarly explained that "Here, we are dealing with a group of utilities with differing risks and business rankings. In our view, the differing ROEs in this group fairly brackets the range of reasonableness for all Midwest ISO TOs."[897] For these reasons, we find that it is still appropriate to retain an RTO-wide base ROE for the MISO TOs.

XV. ROE Incentives Cap

A. Background

447. The Briefing Order proposed to cap a utility's total ROE, i.e., its base ROE plus incentive ROE adders, at the top of the overall composite zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models. The Briefing Order

[895] *See, e.g.*, OMS Initial Br. (I) at 4; OMS Initial Br. (II) at 4.

[896] *MISO Remand Order*, 106 FERC ¶ 61,302 at P 9.

[897] *Id.*

explained that this continued with the Commission's current policy of capping a utility's total ROE at the top of the zone of reasonableness.[898]

B. CAPs

448. CAPs oppose the Commission's proposal, arguing that it is flawed, and assert that the cap on total ROE should be no higher than the top of the zone of reasonableness produced by the DCF model.[899] CAPs contend that the Commission has not provided a reasoned explanation for the proposed departure from Commission precedent of using the DCF zone of reasonableness to set the total ROE cap. CAPs state that the Commission's primary basis for proposing to rely on multiple financial models instead of the DCF alone is that the DCF methodology alone no longer captures how investors view utility returns because investors do not rely on the DCF alone and the other methods used by investors do not necessarily produce the same results as the DCF. CAPs assert that this basis is not founded on reliable record evidence. Accordingly, they assert that the Commission's proposal to use the top of the overall composite zone of reasonableness is not supported.[900]

449. In particular, CAPs argue that inclusion of the Expected Earnings model in the calculation of the overall zone of reasonableness artificially increases the top of the zone in most instances, thereby inflating the total ROE cap and resulting in exploitation of customers.[901] CAPs further contend that, even if the Commission's explanation could support departure from precedent relying on the DCF method, the total ROE cap at the top of the DCF range was established by rulemaking procedures[902] and should continue to apply, unless and until it is changed through a subsequent formal rulemaking.

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[898] Briefing Order, 165 FERC ¶ 61,118 at PP 18, 57.

[899] CAPs Initial Br. (I) at 10; CAPs Initial Br. (II) at 10.

[900] CAPs Initial Br. (I) at 84-85; CAPs Initial Br. (II) at 83-85; CAPs Reply Br. (I) at 76-77; CAPs Reply Br. (I) at 96-97.

[901] CAPs Initial Br. (I) at 84-85; CAPs Br. (II) at 84; CAPs Reply Br. (I) at 76-77; CAPs Reply Br. (II) at 96-97.

[902] CAPs Initial Br. (I) at 85 (citing *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, at PP 92-93 (2006), *order on reh'g,* Order No. 679-A, 117 FERC ¶ 61,345 (2006), *clarified*, 119 FERC ¶ 61,062 (2007)); CAPs Initial Br. (II) at 84-85 (citing Order No. 679, 116 FERC ¶ 61,057 at PP 92-93).

450. CAPs assert that, if the Commission does adopt the top of the overall composite zone of reasonableness as the cap on total ROE, it should adopt CAPs' proposed alternative sequence of calculations that would first calculate, for each proxy company, the average of the different financial models that produce zones of reasonableness to determine a company-specific cost of equity, then use the highest and lowest company-specific composite costs of equity define the upper bound and lower bound of the composite zone of reasonableness, and have that upper bound serve as the cap for the total ROE plus incentives.[903]

C. MISO TOs

451. MISO TOs support the Commission's proposal to cap total ROE plus incentives at the top of the overall composite zone of reasonableness. MISO TOs assert that the Commission's proposal is consistent with the Commission's incentives policy. They argue that it would be irrational for the Commission to adopt a multi-method hybrid approach for analyzing cost of equity and then not use the range of returns produced by that multi-method approach to establish the high end of the range as the cap on total ROE. MISO TOs contend that CAPs provide no justification for placing undue weight on the DCF model solely for the purpose of setting the upper bound on total ROE.[904]

D. Commission Determination

452. Our existing policy is to cap a utility's total ROE—i.e., base ROE in addition to all incentive adders— at the top of the zone of reasonableness.[905] Although we are not changing that policy in this order, we must now incorporate our new method of calculating the overall composite zone of reasonableness into our existing policy. As discussed above, we find that calculating the zone of reasonableness using the DCF and CAPM will more accurately reflect a utility's cost of equity, because it will better represent how investors make their investment decisions. Accordingly, we find that it is appropriate to use the upper end of the composite zone of reasonableness as produced by the revised methodology adopted in this order to cap total ROE rather than only the upper end of the zone of reasonableness produced by the DCF methodology, as CAPs argue.

453. CAPs oppose continuing the Commission's policy of using the top of the overall zone of reasonableness to cap total ROE on the basis that the Commission has not justified using multiple models to calculate the zone of reasonableness instead of only the DCF. We address these arguments in this order, specifically in section III, and explain

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[903] CAPs Reply Br. (I) at 43-45; 77-78; CAPs Reply Br. (II) at 63-65; 97-98.

[904] MISO TOs Reply Br. (I) at 81-82; MISO TOs Reply Br. (II) at 80-81.

[905] *See, e.g.*, Order No. 679, 116 FERC ¶ 61,057 at P 93.

why we find that it is no longer appropriate to use only the DCF model to calculate the zone of reasonableness. For those reasons, CAPs' argument on this point is unavailing.

454. CAPs further argue against capping total ROE with the top of the overall zone of reasonableness by asserting that including the Expected Earnings analysis artificially inflates the top of the zone and thus inflates the total ROE cap because it is an outlier that does not reflect to the market cost of equity. As discussed above in section VI, we are not including the Expected Earnings analysis in our calculation of the overall composite zone of reasonableness. Accordingly, CAPs' arguments on this point are inapposite.

455. In addition, CAPs contend that, even if the Commission could support its approach, the total ROE cap at the top of the DCF range was established by rulemaking procedures and should continue to apply, unless and until it is changed through a subsequent formal rulemaking.[906] CAPs cite a case stating that agencies must "use the same procedures when they amend or repeal a rule as they used to issue the rule in the first instance."[907] We find this argument unavailing. We are not amending or repealing our current policy of using the top of the overall zone of reasonableness to cap total ROE. We are continuing that policy, but amending our previous approach to calculating the overall zone of reasonableness. That approach was established via adjudication and therefore we are "us[ing] the same procedures" to change that approach as we did to implement it "in the first instance."

456. Moreover, we find that, even if this constituted a change to our policy of capping total ROE, we could do so in this proceeding. The Commission "has substantial discretion to establish rules of general application by adjudication and need not necessarily employ a separate generic proceeding."[908] We have similarly explained that

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[906] CAPs Initial Br. (I) at 85 (citing Order No. 679, 116 FERC ¶ 61,057 at PP 92-93; *Perez v. Mortg. Bankers Ass'n,* 135 S. Ct. 1199, 1206 (2015) ("the Administrative Procedures Act 'mandate[s] that agencies use the same procedures when they amend or repeal a rule as they used to issue the rule in the first instance.'")); CAPs Initial Br. (II) at 84-85 (citing same).

[907] CAPs Initial Br. (I) at 85 (citing *Perez v. Mortg. Bankers Ass'n,* 135 S. Ct. 1199, 1206 (2015) ("the Administrative Procedures Act 'mandate[s] that agencies use the same procedures when they amend or repeal a rule as they used to issue the rule in the first instance.'")); CAPs Initial Br. (II) at 84-85 (citing same).

[908] *Procedures for Disposition of Contested Audit*, Order No. 675, 114 FERC ¶ 61,178, at P 32 (2006). *See also NLRB v. Bell Aerospace Corp.*, 416 U.S. 267, 294 (1974) ("[A]djudicative cases may and do serve as vehicles for the formulation of agency policies."); *SEC v. Chenery Corp.*, 332 U.S. 194, 203 (1947) ("[T]he choice made between proceeding by general rule or by individual, ad hoc litigation is one that lies

"[o]ur decision to establish new policy in the context of case-specific proceedings is clearly within our authority."[909] Moreover, we stated in the Briefing Order that "we [did] not make any final determinations with respect to the proposed new methodology,"[910] which included our proposal to cap total ROE with the top of the overall zone of reasonableness,[911] and that we would consider briefing regarding "the justness and reasonableness of any aspect of the proposed methodology."[912]

457. In addition, while briefs were being filed in response to the Briefing Order, the Commission issued an NOI that raised questions regarding the Commission's policy on capping total ROE and indicated that any new policy adopted in these proceedings could be modified in the future, and could be incorporated into the Commission's rules through a formal rulemaking.[913] Accordingly, all parties have had ample notice of and opportunity to address the Commission's proposal to continue with its existing policy of capping total ROE at the top of the overall zone of reasonableness.

458. We are also not persuaded by CAPs' arguments that, if we do adopt the top of the overall composite zone of reasonableness as the cap on total ROE, we should adopt

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primarily in the informed discretion of the administrative agency."); *Michigan-Wisconsin Pipeline Co. v. FPC*, 520 F.2d 84, 89 (D.C. Cir. 1975) ("[T]here is no question that the Commission may attach precedential and even controlling weight to principles developed in one proceeding and then apply them under appropriate circumstances in a stare decisis manner."); *Pacific Gas and Electric Co. v. FPC*, 506 F.2d 33, 38 (D.C. Cir. 1974) ("[A]gency may establish binding policy through rulemaking procedures . . . or through adjudications which constitute binding precedents."); *AEP Power Mktg., Inc.*, 108 FERC ¶ 61,026, at P 187 (2004) ("Our decision to establish new policy in the context of case-specific proceedings is clearly within our authority."); *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 103 FERC ¶ 61,349 at P 51 (2003) ("The Commission, moreover, is not limited to notice and comment rulemaking to develop policy. Agencies generally are permitted considerable discretion to choose whether to proceed by rulemaking or by adjudication.").

[909] *AEP Power Mktg.,*107 FERC ¶ 61,018, at P 199.

[910] Briefing Order, 165 FERC ¶ 61,118 at P 10.

[911] *Id.* PP 18, 57.

[912] *Id.* P 20.

[913] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207, at P 46 (2019).

CAPs' proposed alternative sequence of calculations. As discussed above in section XIII we find that this proposed alternative sequence of calculations would not accurately reflect a utility's cost of equity and we do not adopt that proposal.

XVI. Complaint-Specific Results: First Complaint

459. As discussed above, we find that the revised methodology established in this order will better enable us to identify whether an existing ROE is unjust and unreasonable and, if so, what is a just and reasonable ROE. Applying this methodology to the First Complaint, we continue to find that the MISO TOs' existing 12.38 percent ROE for purposes of the First Complaint is unjust and unreasonable. Having addressed the first prong of the Commission's dual burden under FPA section 206 and thus satisfied the "condition precedent"[914] to exercising our authority to change a rate under section 206, we grant rehearing of Opinion No. 551 and find that a just and reasonable replacement ROE for MISO TOs' in the First Complaint is 9.88 percent under the section prong of the Commission's dual burden under FPA section 206.

460. Below we address the "specific findings"[915] as to the "'particular circumstances'"[916] of the First Complaint proceeding that establish "'a rational connection'"[917] between the record evidence in that proceeding and our decisions under both prongs of section 206 herein to establish that we have "'made a principled and reasoned decision supported by the evidentiary record.'"[918] Because the Commission bases its decisions concerning just and reasonable ROEs for public utilities on the most recent information in the record regarding market cost of equity, the starting point for determining whether MISO TOs' existing ROE has become unjust and unreasonable must be a consideration of whether the current market cost of equity has changed since the MISO TOs' existing ROE was established based on financial for the six months ending February 2002. Accordingly, we begin by determining a composite zone of reasonableness using the most recent financial information in the record of the First Complaint proceeding, i.e., data for the first six months of 2015.

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[914] *Emera Maine*, 854 F.3d at 25 (citing *FPC v. Sierra Pac. Power*, 350 U.S. 348, 353 (1956)).

[915] *Id.* at 30.

[916] *Id.* at 27 (citing *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

[917] *Id.* at 28 (citing *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 782 (2016)).

[918] *Id.* at 30 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 181).

A. Composition of Starting Proxy Group

461. As described in the Briefing Order,[919] the Commission uses the following screens for developing a proxy group: (1) the use of a national group of companies considered electric utilities by *Value Line*; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose ROE is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six month study period; (4) the inclusion of companies with no merger activity during the six-month study period that is significant enough to distort the study inputs; and (5) companies whose ROE results pass threshold tests of economic logic, including the low-end outlier test and high-end outlier test adopted in section X of this order. The first four screens listed above evaluate particular characteristics of the companies in question that do not vary depending upon the results of the DCF or CAPM analyses. Accordingly, those screens may be used to develop a starting group of proxy companies eligible for inclusion in the proxy group to be used for the purposes of both the DCF and CAPM models. The low-end and high-end outlier tests must then be applied separately to the results of the DCF and CAPM models to determine the final DCF and CAPM proxy groups. Below, we first address issues concerning the determination of the starting proxy group in the First Complaint proceeding. We then apply the low-end and high-end outlier tests to the results of the DCF and CAPM analyses in order to determine the DCF and CAPM zones of reasonableness.

1. Opinion No. 551

462. The Presiding Judge determined that the DCF Study Period for calculating the zone of reasonableness should be the most recent six-month period for which there is financial data in the record, January to June 2015.[920]

463. In order to establish a proxy group, the Presiding Judge reviewed the DCF-determined cost of equity for 42 companies. The Presiding Judge determined that 40 of those companies should be included in the proxy group, before application of any low or high-end outlier test. Of those companies, the lowest cost of equity was Edison International's 4.38 percent and the highest cost was TECO's 11.35 percent.[921] The Presiding Judge rejected contentions that TECO should be excluded from the proxy group because of certain Merger and Acquisition (M&A) Activity. The Presiding Judge excluded Madison Gas and Electric Energy, Inc. because it did not have a credit rating

[919] Briefing Order, 165 FERC ¶ 61,118 at PP 50-51.

[920] Initial Decision (I), 153 FERC ¶ 63,027 at PP 56, 61.

[921] *Id.* at App. A.

from either Moody's Investors Service or S&P and, therefore, could not be shown to have a credit rating of not more than one notch above or below MISO TOs, as required by Opinion No 531.[922] In addition, the Presiding Judge also excluded Unitil Corporation (Unitil) from the proxy group because it is not one of the companies covered by *Value Line* and because, unlike the companies in *Value Line*, Unitil has a capitalization of less than $1 billion.[923]

464. Complainants, Joint Customer Intervenors, and Trial Staff excepted to the Presiding Judge's inclusion of TECO in the proxy group.[924] No participant filed exceptions to any of the Presiding Judge's other rulings with respect to the proxy group.

465. In Opinion No. 551, the Commission affirmed the Presiding Judge's decision to include TECO in the proxy group.[925] Citing Opinion No. 531, the Commission explained that "it is the Commission's 'practice . . . to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the [company's] DCF inputs" — i.e., the company's "stock prices, dividends, or growth rates."[926] The Commission stated that it does not exclude a company simply because it has engaged in any M&A activity or that activity may cause changes in the DCF inputs.[927] Rather, the Commission stated that it excludes a company if the M&A activity may cause temporary changes in DCF inputs that are not sustainable or representative of longer-term investor expectations for the company.

466. As noted in Opinion No. 551, TECO engaged in two M&A activities that could potentially require its exclusion from the proxy group. First, on September 2, 2014, nearly four months before the beginning of the updated the study period, TECO completed its acquisition of New Mexico Gas Company (New Mexico Gas). The record reveals that, several months later, during the January 2015 to June 2015 study period,

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[922] *Id.* PP 70, 72 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 106).

[923] *Id.* PP 74-75, 77.

[924] Opinion No. 551, 156 FERC ¶ 61,234 at PP 30-34.

[925] *Id.* PP 37-43.

[926] *Id.* P 23 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 114).

[927] *Id.* (citing Opinion No. 489, 117 FERC ¶ 61,129 at PP 67-68 ("We also reject [the] . . . argument that Commission precedent supports, in every instance, the exclusion from a proxy group of any utility engaged in merger activity."), *order on reh'g*, 122 FERC ¶ 61,265, *order on clarification*, 124 FERC ¶ 61,136 (2008)).

analysts were still assessing the impact of the New Mexico Gas acquisition on TECO earnings.[928] For example, the May 22, 2015 issue of *Value Line* noted that the acquisition should increase TECO's earnings, although the acquisition was just one of several factors, including strong customer growth and impending rate increases, that *Value Line* identified to support the projected increase in TECO's earnings for 2015 and 2016.[929]

467. Second, on October 20, 2014, roughly a month after closing the New Mexico Gas acquisition, TECO announced an agreement to sell its coal mining subsidiary, TECO Coal Corporation (TECO Coal) to Cambrian Coal Corp. (Cambrian) for $120 million and a contingent payment of up to $50 million, depending on coal prices.[930] TECO's stock price rose approximately 8 percent in the month following news of the sale. A few months later, in February 2015, TECO announced an amendment to the terms of the agreement that lowered the purchase price to $80 million, but increased the maximum contingent payment to $60 million.[931] Later in February, a securities analyst at UBS upgraded TECO from "neutral" to "buy," noting the potential sale of TECO Coal as one of the reasons for the upgrade. Throughout this period in early 2015, IBES's growth projections for TECO increased from 6.43 percent in January to 7.08 percent in February and all the way up to 9.20 percent by March 2015, even as at least one analyst expressed skepticism that TECO would complete the sale of TECO Coal.[932]

468. In April 2015, TECO announced that it was considering selling TECO Coal to other potential buyers in the event that the deal with Cambrian fell through.[933] As it happened, TECO announced in June 2015, the last month of the study period, that the deal with Cambrian had not closed as scheduled, but that it had received a non-binding offer for TECO Coal from an undisclosed buyer. The IBES growth projections remained steady at 9.20 percent throughout April, May, and June, notwithstanding the multiple reports casting doubt on TECO's ability to complete the sale of TECO Coal.[934] In early

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[928] *Id*. P 24.

[929] Initial Decision (I), 153 FERC ¶ 63,027 at P 91; Ex. S-6 at 161.

[930] Initial Decision (I), 153 FERC ¶ 63,027 at P 98; Ex. S-3.

[931] Initial Decision (I), 153 FERC ¶ 63,027 at P 98. The terms of the sale were amended again in mid-April 2015.

[932] *Id.* P 101; Ex. S-4 at 15; S-6 at 147, 171.

[933] Initial Decision (I), 153 FERC ¶ 63,027 at P 99.

[934] *Id.* P 101; Ex.S-6 at 149, 151.

July 2015, TECO announced that it had failed to reach an agreement with the undisclosed buyer, but that a sale of TECO Coal to Cambrian remained a possibility. A week later, on July 13, 2015, IBES's growth projection for TECO declined to 7.68 percent.[935] The Presiding Judge used the 7.68 percent IBES growth projection in his DCF analysis of TECO.

469. Opinion No. 551 affirmed the Presiding Judge's conclusion that neither the acquisition of New Mexico Gas nor the attempted sale of TECO Coal was sufficient to "distort" the DCF inputs.[936] In Opinion No. 551, with respect to New Mexico Gas, the Commission noted the Initial Decision's finding that TECO's acquisition of New Mexico Gas was completed on September 2, 2014, nearly four months before the beginning of the updated study period, which covered January-June, 2015.[937] As such, the Commission determined that speculation about whether the acquisition would be completed could not have affected, much less distorted, the stock price or the other DCF inputs during the updated study period. The Commission rejected Complainants' contention that TECO should be excluded on the grounds that the acquisition of New Mexico Gas created a temporary and unsustainable increase in TECO's expected earnings. As an initial matter, the Commission found that, over the course of the updated study period, the IBES growth estimates increased 125 basis points, not 280 basis points that Complainants' witness Mr. Gorman testified to.[938] However, the Commission further noted, as illustrated by the July 13, 2015 *Yahoo! Finance* data included along with the testimony of Joint Consumer Advocates' witness Mr. Hill, the actual projected earnings growth for TECO at the end of

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[935] Initial Decision (I), 153 FERC ¶ 63,027 at P 101. The Presiding Judge's Order Establishing Procedural Schedule provided that the cut-off date for data to be used by any party in updates of ROE studies would be July 13, 2015. Ex. JCA-22.

[936] Initial Decision (I), 153 FERC ¶ 63,027 at PP 81, 96, 106.

[937] Opinion No. 551, 156 FERC ¶ 61,234 at P 38.

[938] *Id.* (citing Ex. JC-22 at 7). In making that finding, the Commission rejected Complainants' contention that there was a disputed issue of fact regarding the appropriate growth rate for TECO at the end of the updated study period. The Commission affirmed the Presiding Judge's decision to rely on Mr. Hill's 7.68 percent growth rate, determining that Mr. Hill's testimony states clearly that he relied upon the numbers from *Yahoo! Finance* on July 13, 2015, the cut-off date for ROE data used in the updated study period, to evaluate TECO's merger activity. By contrast, the Commission determined that there was nothing in Mr. Gorman's testimony that suggests that he used July 13, 2015 IBES data – and not data from earlier in the study period, when the IBES growth rate was 9.20 percent when deciding whether to exclude TECO from the proxy group. *Id*. P 50 n.88.

the updated study period used in the parties' DCF analysis was 7.68 percent, 125 basis points above the 6.43 percent at the beginning of the study period.[939]

470. The Commission concluded that there was no evidence in the record suggesting that the New Mexico Gas acquisition caused a significant and unsustainable increase in TECO's earnings expectations during the updated study period. The Commission determined that the May 22, 2015 *Value Line* report suggested that the acquisition will increase earnings "over and above" the savings TECO will realize from no longer paying transaction costs associated with the acquisition. The Commission found that there was nothing suggesting that the additional increase is unsustainable. After all, the Commission determined, all other things being equal, an earnings increase is what would be expected when a company increases its regulated gas and electric customers by 50 percent, as TECO did in acquiring New Mexico Gas.[940] The Commission further stated that, in any case, the acquisition was just one of many factors, along with rate increases for TECO's Florida utilities and an anticipated reduction in TECO's cost of debt, which supported *Value Line*'s increased earnings projections.[941] The Commission determined that the *Value Line* report thus was not evidence suggesting that the acquisition distorted TECO's expected growth rate based on temporary, short-term developments that are unlikely to continue.[942]

471. Regarding TECO's attempts to sell TECO Coal, the Commission similarly concluded that there was no evidence suggesting that those efforts "distorted" the DCF inputs. The Commission stated that, unlike the acquisition of New Mexico Gas, the efforts to sell TECO extended into the updated study period and, therefore, it was possible that speculation related to the potential merger could have affected TECO's DCF inputs. Nevertheless, the Commission concluded that any effect was either too small or

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[939] *Id*.

[940] *Id*. P 39. To the extent that the parties suggested that TECO should be excluded because its earnings outlook improved because it was no longer incurring the transaction cost associated with the acquisition, the Commission rejected their argument. The Commission stated that adopting that position would require that it exclude companies for a year after almost any major merger or acquisition as the savings from no longer incurring the transaction costs materialize in annual earnings. The Commission stated that that result is not the purpose of the M&A screen. *Id*. P 50 n.89.

[941] *Id*. P 39 (citing Initial Decision (I), 153 FERC ¶ 63,027 at P 91).

[942] *Id*.

too attenuated to rise to the level of a distortion requiring TECO's exclusion from the proxy group.[943]

472. The Commission found that that the record did not show that the attempted sale of TECO Coal distorted TECO's expected earnings. Noting that TECO Coal represents less than 1.5 percent of TECO's total market capitalization,[944] the Commission determined that the sale of such a relatively small asset is, as a general matter, not the type of input-distorting transaction that the M&A screen is intended to address. Additionally, the Commission stated that many of the public utilities, especially relatively large companies that make a good comparison for TECO, are regularly engaged in potential mergers or acquisitions of small business units or subsidiaries. It stated that excluding such companies from the proxy group on the basis of any small purchase or sale would unnecessarily shrink the group of representative companies, thereby making the proxy group, and the resulting DCF analysis, a less reliable tool for ensuring that the allowed ROE satisfies the requirements of *Hope* and *Bluefield*.[945]

473. The Commission determined that the evidence in this case confirmed that TECO's potential sale of its underperforming asset, TECO Coal, had little impact on its projected growth rates or stock prices. As the Presiding Judge observed, IBES's projected growth rates for TECO steadily increased throughout the first five months of the six-month study period, even as the prospects for selling TECO Coal steadily deteriorated.[946] The Commission stated that, if the potential sale of TECO Coal was a significant factor affecting TECO's DCF inputs, it would anticipate at least some decline in the expected growth rate as the prospects for a sale deteriorated between February and June, 2015. Instead, TECO's expected growth rate first increased between February and March and then held steady through June.[947] In short, the Commission concluded that the record

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[943] *Id*. PP 40-43.

[944] While noting the possibility that the expected earnings growth rate would have further increased during this period were it not for the eroding chances of a successful sale of TECO Coal, the Commission concluded that there was no evidence in the record suggesting that the decreasing likelihood of a sale provided any such drag on TECO's earnings expectations. *Id*. P 51 n.91.

[945] *Id.* P 41.

[946] Initial Decision (I), 153 FERC ¶ 63,027 at P 103.

[947] *Id.* P 101.

simply did not suggest that the potential sale had much, if any, effect on the growth rate used in the DCF analysis.[948]

474. Similarly, the Commission concluded that there was no evidence in the record that the attempted sale of TECO Coal caused a distortion in TECO's stock price. The comparison of TECO's stock price versus the Dow Jones Utility Average submitted by Dr. Avera showed that the two moved in near lockstep from November 2014 through April 2015, which significantly overlapped with the study period. In any case, Dr. Avera's graph showed that TECO outperformed the industry average by an even greater amount for much of March and April, 2015, when the chances of a successful sale appeared to be diminishing.[949] Once again, the Commission determined that, if the potential sale of TECO Coal was affecting TECO's DCF inputs in any significant way, it would not expect to see TECO's stock price performing well relative to the industry average even as the prospects for the sale declined. The Commission stated that, although it might be argued that looking at relative performance is somewhat misleading, and that TECO's stock would have performed consistently worse relative to the industry average were it not for the potential sale, there was no evidence in the record suggesting that that is the case here and the Commission's M&A screen did not require a company's exclusion from the proxy group on so speculative a basis.[950]

2. Request for Rehearing

475. CAPs state that because TECO's 11.35 percent market cost of equity is the highest of all proxy group companies, TECO, if it is included, sets the upper end of the zone of

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[948] Opinion No. 551, 156 FERC ¶ 61,234 at P 42.

[949] The Commission noted that the Presiding Judge did not rely on Dr. Avera's chart because the y-axis for TECO's stock price was smaller relative to the y-axis for the industry average, which, according to the Presiding Judge, caused Dr. Avera's chart to underrepresent the variation in TECO's stock price. But, the Commission stated, that observation did not require it to change its conclusion, which rested in part on the fact that TECO's stock price performed better relative to the industry average when the prospects for the sale dimmed, than when the sale appeared most likely to occur. *Id.* P 53 n.95.

[950] *Id*. P 43. Although there was evidence in the record that some analysts viewed TECO Coal as "a drag on shares" of TECO, the Commission found that that evidence did not suggest that the increasingly dim prospect of eliminating that "drag" was sufficient to "distort" the DCF inputs, especially given the absence of any apparent correlation between the DCF inputs and the prospects for a successful sale of TECO Coal. *Id*. P 56 n.97 (citing Initial Decision (I), 153 FERC ¶ 63,027 at P 100).

reasonableness, thereby having a significant impact on the determination of the midpoint. CAPs state that it is important in this case to ensure that the high end of the DCF range is not associated with DCF model inputs that may been distorted by merger-related activity. CAPs argue that, consistent with Commission precedent, TECO should be excluded from the proxy group due to M&A activity that distorted TECO's DCF inputs during the relevant study period.[951]

476. CAPs argue that, in Opinion No. 551, the Commission did not properly apply the standard established by the Commission in Opinion No. 531. They argue that the Commission's application of the M&A screen in Opinion No. 531 focused on whether the M&A activity is significant enough to cause a distortion to the DCF inputs, not whether the M&A activity distorts DCF inputs only on a basis that is "temporary" or "not sustainable." They argue that by imposing on parties the additional burden of demonstrating that the impact on DCF inputs will be temporary or unsustainable in Opinion No. 551, the Commission departed from established precedent without explanation. They further contend that the Commission failed to explain how a party can demonstrate in advance whether the effect of particular M&A activity will be sustainable.[952]

477. Citing TECO's acquisition of New Mexico Gas and the sale of its subsidiary TECO Coal, CAPs argue that the record demonstrates that TECO was engaged in various M&A activities throughout the study period and that such M&A activity distorted the DCF inputs.[953] CAPs contend that neither Opinion No. 531 nor any precedent cited therein supports the proposition that a certain level or duration of distortion is required to exclude a utility from the proxy group. They further contend that Commission precedent is also silent on whether the distortion must occur in a certain direction (positive or negative) in order to warrant removal group.[954] In addition, they argue that M&A activity

[951] CAPs Rehearing Request at 9-10. CAPs state that the Joint Consumer Advocates opt out of CAPs' rehearing request on this issue.

[952] *Id*. at 10.

[953] *Id*. at 11 (citing Initial Decision (I), 153 FERC ¶ 63,027 at PP 100-101).

[954] *Id*. at 12 (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at PP 79, 81 (explaining that, here, the Commission's removal of a utility from the proxy group was based, in part, on the basis that the utility's M&A activity "can distort that share prices by creating uncertainty (positive or negative) about the impact of change")).

is not limited to activity within the study period, but may include activity that is "recent, current, or forecasted."[955]

3. Briefs

478. CAPs witness Mr. Solomon argues for the exclusion of TECO from the proxy group.[956] Mr. Solomon asserts that TECO's DCF study inputs were distorted during the relevant study period, January to June 2015, as a result of its major M&A activity.[957] Mr. Solomon contends that the late October 2014 announcement of the agreement to sell TECO Coal had the effect of increasing TECO's price relative to the SNL Energy stock index, and it subsequently maintained that higher relative price throughout the study period ending June 30, 2015, demonstrating the continuing effect the expected sale of TECO Coal had on TECO's stock price. Mr. Solomon states that changes in TECO's stock price followed changes in the SNL Energy group average price relatively closely from July 1, 2014, until the late October 2014 announcement of the agreement to sell TECO Coal, when there was a clear increase in the price of TECO Energy stock relative to the SNL Energy average price. He states that, with some fluctuations, the TECO price subsequently maintained that relative price spread, indicating the continuing favorable effect the expected TECO Coal sale had on the TECO stock price. He argues that this effect on key market-based data requires TECO's exclusion from the proxy group.[958]

479. Mr. Solomon also states that, on July 16, 2015, shortly after the conclusion of the study period in this proceeding, TECO disclosed that it was exploring strategic alternatives, which could include a sale of the entire company. He states that in reaction, shares of TECO spiked that day, justifying excluding TECO from the proxy group.[959]

480. With regard to the Judge's conclusion that TECO should not be excluded from the proxy group because, if anything, the distortion reduces the resulting DCF study ROE input, Mr. Solomon contends that the purpose of the M&A screen is not to determine

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[955] *Id*. (citing *Atlantic Grid Operations*, 135 FERC ¶ 61,144, at P 88 n.55 (2011) (finding proxy group screens for "significant recent, current or forecasted merger activity to be appropriate)).

[956] CAPs Initial Br. (I), Ex. JCI-100 (Solomon Aff.) at 11.

[957] *Id*. at 54 (citing Initial Decision (I), 153 FERC ¶ 63,027 at PP 56 and 60; Opinion No. 551, 156 FERC ¶ 61,234 at P 19).

[958] *Id*. at 55.

[959] *Id*. at 55-56.

whether a distorted input causes an increase or decrease in the resulting ROE. He argues that the criterion described in Opinion No. 531 and elsewhere simply requires the exclusion of companies that engaged in significant M&A activity where such activity distorts study inputs, which compromises the integrity of the model's output in respect of the company subject to M&A activity.[960]

481. Mr. Solomon states that the Commission's rationale in affirming the Initial Decision is in contrast to the views expressed by the Judge. According to Mr. Solomon, whereas the Judge declined to exclude TECO from the proxy group on the ground that the price spike caused TECO's dividend yield and 11.35 percent DCF result, which set the top of the range, to be lower than it should be and that excluding TECO would lower the top of the range even more, the Commission instead found that the effect was too small to remove TECO Energy from the proxy group.[961] Mr. Solomon argues that the Commission responded only indirectly to the Judge's finding that TECO's stock price was affected by its announced intention and subsequent attempts to sell TECO Coal.

482. First, Mr. Solomon states that, in finding that the potential sale had little or no effect on the growth rate used in the DCF analysis, the Commission did not use the 9.20 percent growth rate that was in place from March through June in the approved DCF calculations, but rather used the 7.68 percent growth rate from July 13, 2015, which was some 152 basis points, or 16.5 percent, lower. Mr. Solomon further contends that although the Commission cited the Initial Decision at P 103 where the Presiding Judge concluded that there was no evidence "that the 7.68 percent projection was the result of distortions resulting from TECO's attempts to sell TECO Coal," the Presiding Judge also did not cite any evidence to the contrary. Nonetheless, Mr. Solomon argues, TECO's projected growth rate did drop in July 2015, likely for multiple reasons including its declining prospects for unloading TECO Coal. It was also not until July 6, 2015 that Standard and Poor's removed TECO Energy from CreditWatch due to its failure, to that point, to find a buyer for TECO Coal.[962]

483. Second, Mr. Solomon challenges what he characterizes as the Commission's apparent reliance upon a chart produced by MISO TO witness Dr. Avera that purportedly demonstrates that TECO's stock price moved in near lockstep with the Dow Jones Utility Average during much of the study period.[963] Mr. Solomon states that the Presiding Judge

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[960] *Id*. at 56-57.

[961] *Id*. at 57-58.

[962] *Id*. at 58-59.

[963] *Id*. at 59 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 43).

expressed concern that Dr. Avera's chart created an optical illusion (because the variation in the scale on the two axes was not equal) which, when corrected for the optical illusion, "would likely result in a price pattern comparable to that shown on Mr. Solomon's graph."[964]

484. In addition, Mr. Solomon notes that, on February 10, 2015, during the study period, a UBS securities analyst advised SNL Financial that the sale of TECO Coal would remove a large drag on shares. Thus, as the Presiding Judge found, there is evidence in the record to demonstrate that the TECO stock price was affected by TECO's announcement of an agreement to sell and subsequent attempts to sell its underperforming TECO Coal subsidiary prior to which *Value Line* had found had weighed on the stock.[965]

485. Mr. Solomon also argues that there was an increase in TECO's projected earnings growth rate during the study period that was at least partially attributable to TECO's acquisition of New Mexico Gas, which increased TECO's regulated gas and electric customers by 50 percent. Mr. Solomon argues that, while this acquisition was completed almost four months prior to the beginning of the DCF study period, it certainly impacted the expected growth rate for TECO Energy. Mr. Solomon states that it is undisputed that TECO's expected earnings growth rate increased from 6.43 percent at the beginning of study period, to the 7.68 percent the Commission found appropriate to use in the DCF analysis by the end of the study period. Mr. Solomon argues that, while the New Mexico Gas acquisition was likely only one of many factors, including rate increases for TECO's Florida utilities and an anticipated reduction in TECO Energy's cost of debt, contributing to the expected growth earnings increase, the resulting 50 percent in regulated gas and electric customers had to be a major contributor and there has been no showing that it was not.[966]

486. Further, Mr. Solomon disagrees with the Commission's conclusion in Opinion No. 551 that there was no evidence in the record suggesting that the New Mexico Generation acquisition caused a significant and unsustainable increase in TECO's earnings expectations during the updated study period. First, Mr. Solomon argues that an

[964] *Id*. (quoting Initial Decision (I), 153 FERC ¶ 62,027 at P 105).

[965] *Id*. at 60.

[966] *Id*. at 60-61.

increase in TECO's expected earnings per share growth rate from 6.43 percent to 7.68 percent—a more than 19 percent increase—is not insignificant.[967]

487. Second, Mr. Solomon argues that the finding of sustainability is misdirected. Mr. Solomon argues that the Commission's statement that an earnings increase would be expected when a company increases its regulated gas and electric customers by 50 percent, as TECO did in acquiring New Mexico Gas, misses the point.[968] According to Mr. Solomon, the point is that the acquisition caused a one-time increase in the expected earnings growth rate, not a one-time increase in the absolute level of expected earnings. Mr. Solomon argues that, after the acquisition is assimilated with a higher base level of earnings, changes in the expected growth rate will not be as large. He contends that while some analysts may make adjustments in an attempt to restate the historical data to account for the acquisition, others may not and, in any event, such adjustments are difficult to quantify.[969]

488. Moreover, Mr. Solomon argues, the *Value Line* betas used for the CAPM analysis are based on historical prices for the last five years and are less certain to be representative of future betas for TECO now that TECO Energy has increased its regulated electric and gas customer base by 50 percent with the New Mexico Gas acquisition, which not only significantly changed the number, but also the composition of its electric versus gas service.[970]

489. MISO TOs respond that Mr. Solomon's argument that TECO is not a proper proxy due to its M&A activity flies in the face of the Commission's prior findings in Opinion No. 551 that there is no evidence in the record suggesting that the New Mexico Gas acquisition caused a significant and unsustainable increase in TECO's earnings expectations during the dated study period, or that such activity operated to distort the DCF inputs.[971]

490. In a reply affidavit, MISO TOs' witness, Mr. McKenzie, argues that Mr. Solomon's arguments to exclude TECO Energy from the proxy group should be rejected. First, Mr. McKenzie argues that the issue of whether to include TECO Energy

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[967] *Id*. at 61.

[968] *Id*. at 61-62 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 39).

[969] *Id*. at 62.

[970] *Id*.

[971] MISO TOs Reply Br. (I) at 51.

in the proxy group in Docket No. EL14-12-000 is not in any way related to the ROE methodology proposed in the Briefing Order.[972] Mr. McKenzie contends that neither the Court's findings in *Emera Maine* nor the Commission's ROE methodology in the Briefing Order pertain to the evaluation of proxy group companies. Mr. McKenzie argues that Mr. Solomon is improperly attempting to broaden the scope of inquiry, none of his arguments raised in his affidavit are based on new information and that Mr. Solomon is simply second-guessing the Commission's previous determination that TECO belongs in the proxy group.[973] Mr. McKenzie also states that the Commission, in Opinion No. 531, specifically ruled out excluding proxy companies without a demonstration that the transaction impacted the DCF results by distorting the companies' stock prices, dividends, or growth rates.[974]

491. In response to Mr. Solomon's assertion that Dr. Avera's chart created an optical illusion, Mr. McKenzie presents a chart using the same data comparing the TECO stock price with the Dow Jones Utility Average. But, in response to the Presiding Judge's concerns, the values on the two axes are both scaled by exactly 25 percent. Mr. McKenzie asserts that his chart shows that there is no indication of systemic distortion in TECO's stock prices, relative to broader trends for the utility industry.[975] Meanwhile, argues Mr. McKenzie, the chart presented by Mr. Solomon[976] does not compare the movement of TECO Energy's stock price to the corresponding trend for utilities as a whole. Mr. McKenzie contends that the diverse group of companies in the SNL Energy stock index used in Mr. Solomon's comparison is not indicative of price trends for a utility like TECO. Further, Mr. McKenzie argues that Mr. Solomon's figure is a comparison of cumulative percentage changes in value from a selected beginning point, which is arbitrary.[977]

492. Moreover, Mr. McKenzie states that, as Dr. Avera documented, the cash price for TECO's coal subsidiary represented less than 1.5 percent of TECO Energy's total capital. Mr. McKenzie argues that Mr. Solomon's speculation that the sale of an asset that had

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[972] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 126.

[973] *Id*.

[974] *Id*. at 127 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 114).

[975] *Id*. at 128-129.

[976] Ex. JCI-8 at 7.

[977] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 129-130.

already been classified as discontinued since the third quarter of 2014 would somehow motivate a 20 percent revaluation of TECO's stock price is illogical and unsupported.[978]

4. Determination

a. Commission Response to Rehearing Arguments

493. We are not persuaded by CAPs' argument, reiterated in their briefing arguments, that the Commission's application of the M&A screen in establishing the starting proxy group did not properly apply the standard established in Opinion No. 531. CAPs argue that Opinion No. 531 requires exclusion from the proxy group of any company whose M&A activity caused a change in its DCF inputs. They contend that Opinion No. 551 improperly altered that standard by requiring them to show not only that TECO's M&A activity had an impact on its DCF inputs, but also that that impact was "temporary" or "not sustainable."

494. Opinion No. 551 properly considered whether TECO's M&A activity "may cause temporary changes in DCF inputs that are not sustainable or representative of longer-term investor expectations for the company."[979] In Opinion No. 531, the Commission, citing precedent, noted that its practice is to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the DCF inputs, based on the facts and circumstances of each case.[980] The DCF inputs are "distorted" if they are not representative of longer-term investor expectations for the company, for example because the M&A activity has caused a temporary jump in stock price or an unsustainable growth projection. However, if a completed M&A activity has caused a sustainable change in a DCF input, as the Commission found with respect to TECO's purchase of New Mexico Gas, then the DCF inputs are representative of longer-term investor expectations and the company is properly included in the proxy group.

495. Opinion No. 531 and the precedent it cited is not inconsistent with this interpretation of our M&A screen. For example, Opinion No. 531 cited the Presiding Judge's initial decision in *Bangor Hydro-Electric Co*., which the Commission affirmed. In that initial decision, the presiding judge held that the facts and circumstances of that case did not warrant exclusion of the companies at issue from the proxy group:

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[978] *Id.* at 130.

[979] Opinion No. 551, 156 FERC ¶ 61,234 at P 37.

[980] Opinion No. 531, 147 FERC ¶ 61,234 at P 114 (citing, among other cases, *Bangor Hydro-Electric Co*., 111 FERC ¶ 63,048, at PP 67-68, *aff'd in relevant part*, Opinion No. 489, 117 FERC ¶ 61,129).

> I agree with the testimony presented by the [New England TOs] that "Whether or not [the anticipation of a merger] does or does not [affect the market] *depends on the facts and circumstances*. If a very large company acquires a very small company, it typically is not very material to the very large company. It may be material to the small company, depending on whether there's a premium or investors revise their expectations markedly . . . *whether a merger makes a big effect or not depends on the facts and circumstances*." Tr. 297-98. In this the [New England TOs] presented testimony that the anticipation of merger did not distort stock prices, and therefore, although I agree that whether a company is engaged in merger activity should be a criterion for examination when choosing a proxy group, *in this case* neither PSEG nor Exelon should be eliminated on this basis.[981]

496. In Opinion No. 531 the Commission similarly analyzed whether the M&A activity was significant enough to distort the DCF inputs, based on the facts and circumstances of that case. It affirmed the initial decision's approval of the elimination of two utilities from the proxy group based on their recent M&A activity as well as finding that the record did not indicate that a third utility's recent M&A activity was significant enough to distort the DCF inputs.[982]

497. Sustainability of the impact of M&A activity on growth was not at issue in Opinion No. 531. By contrast, the record relied upon by the Commission in Opinion No. 551 does include evidence of the sustainability of the impact of the M&A activity, specifically the purchase of New Mexico Gas, on growth, and nothing in Opinion No. 531 restricted the Commission from considering such record evidence in making its determination in Opinion No. 551. Further, in the Briefing Order, the Commission "recognize[d] that in unusual circumstances the two-step DCF methodology may produce *unsustainably* high results for a particular proxy company."[983]

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[981] 111 FERC ¶ 63,048 at P 67 (emphasis added).

[982] Opinion No. 531, 147 FERC ¶ 61,234 at P 114.

[983] Briefing Order, 165 FERC ¶ 61,118 at P 53 (emphasis added). *See also, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 98 (2008), *order on reh'g*, 133 FERC ¶ 61,152, at PP 20, 64 (2010); *ISO New England, Inc.*, 111 FERC ¶ 61,344, at P 8 (2005).

b. Commission Response to Briefing Arguments

498. We agree with MISO TOs that additional arguments and evidence regarding whether to exclude TECO from the starting proxy group that parties provided in their briefs is outside the scope of the Briefing Order. In the Coakley Briefing Order, the Commission set forth a framework for addressing proposed revised methodology for rate of return. As noted above, in the Briefing Order, the Commission sought comments on whether to apply the methodology it proposed in the Coakley Briefing Order. While the Commission said that all aspects of the proposed methodology were subject to comment and that parties could provide evidence, the Commission did not propose to change its screens for developing a proxy group, instead proposing to use the same screens as in Opinion Nos. 531 and 551.[984] Moreover, CAPS do not oppose the Briefing Order's proposed M&A screen itself.[985] Rather, CAPs briefing argument, through Mr. Solomon's testimony, is confined to reiterating CAPs' opposition to the inclusion of TECO in the proxy group. But, even if Mr. Solomon's arguments were properly within the scope of the Briefing Order, we find them unpersuasive, as discussed below.

499. Mr. Solomon's argument that the Commission's rationale with respect to the proposed sale of TECO Coal differed from that of the Presiding Judge is unpersuasive. The Commission may affirm the ultimate decision of the Initial Decision for different reasons than put forth by the Presiding Judge where, as in this case, there is a complete evidentiary record of the issue enabling the Commission to affirm the Initial Decision's ultimate conclusion.[986] Moreover, in this case, as we discuss below, the MISO TOs' introduced additional evidence in their reply to the CAPs' brief that addressed concerns raised by the Presiding Judge in his Initial Decision.

500. CAPs contend that TECOs' purchase of New Mexico Gas caused a one-time increase TECOs' growth rate by increasing TECOs' regulated gas and electric customers

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[984] *Id*. P 50.

[985] CAPs Initial Br. (I) at 25-26.

[986] *See, e.g., Old Dominion Elec. Coop*., 158 FERC ¶ 61,045, at P 72 n.107 (2017) (affirming the Initial Decision's ultimate conclusion that a revised base energy rate was just and reasonable, despite disagreeing with the Initial Decision's statement that it was an unchanged element of the applicant's formula rate, because there was a complete evidentiary record on the issue), *reh'g denied*, 162 FERC ¶ 61,262 (2018); *Pub. Serv. Co. of Indiana Inc.*, 7 FERC ¶ 61,319, at 61,701, *order on reh'g*, 8 FERC ¶ 61,224 (1979) (affirming the Initial Decision's finding that purchased power estimates were reasonable, but for different reasons than expressed in the Initial Decision), *order on reh'g*, 14 FERC ¶ 61,058 (1981).

by 50 percent. CAPs point out that the IBES short-term year growth projection for TECO increased from 6.43 percent at the beginning of the January to June 2015 study period to the 7.68 percent IBES growth projection on July 13, 2015, which the Commission found appropriate for use in TECO's DCF analysis. CAPs argue that, after TECO's acquisition of New Mexico Gas is assimilated with the higher base level of earnings resulting from the increase in its customers, the longer term increase in TECO's earnings will not be as large.

501. The Presiding Judge addressed this issue in his Initial Decision.[987] Relying on a May 22, 2015 *Value Line* report, the Presiding Judge found that there were additional reasons beyond the New Mexico Gas purchase for TECO's growth rate to increase. That report found that TECO's Tampa Electric and Peoples Gas utilities in Florida were experiencing strong customer growth as the Florida economy expands, and Tampa Electric was benefitting from a rate hike that took effect in November 2014. Also, TECO was planning to replace maturing high-cost debt with borrowings that had a much lower interest rate. Furthermore, the Presiding Judge pointed out that the May 22, 2015 *Value Line* report stated,

> *We forecast continued bottom-line growth in 2016.* We expect the favorable trends at the Florida utilities to persist, and New Mexico Gas is also experiencing some growth, albeit modest. We estimate that earnings will rise 4%-5%, to $1.15 a share. A more significant increase is likely in 2017, as Tampa Electric's rates will be raised by $110 million once an upgrade to a power plant is completed.[988]

The Presiding Judge reasonably found that this statement indicated that *Value Line* did not expect any one-time effects of the New Mexico Gas purchase to extend beyond 2015 into 2016. Rather, New Mexico Gas's contribution to TECO's growth after 2015 would derive not from the two companies' combination of earnings, but from New Mexico Gas' own modest increase in earnings. In these circumstances, we continue to find that the July 13, 2015 IBES projection of TECO's growth over the next three to five years may be treated as representative of longer-term investor expectations of sustainable growth and not significantly affected by any one-time effects of the New Mexico Gas purchase, which was completed over 10 months earlier.

502. CAPs also dispute Opinion No. 551's holding that TECO's October 20, 2014 announcement of an agreement to sell TECO Coal to Cambrian for $120 million and a contingent payment of up to $50 million, depending on coal prices, did not distort its

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[987] See Initial Decision (I), 153 FERC ¶ 63,027 at PP 89-96.

[988] *Id*. P 93 (citing Ex. MTO-54 at 41 (emphasis in *Value Line* report)).

DCF inputs during the January to June 2015 study period. CAPs cite various *Value Line* reports from before the October 20, 2014 announcement noting that the coal mining business had become a drag on TECO, and a November 21, 2014 *Value Line* report stating that TECO's stock had increased by 8 percent since the announcement.[989] CAPs also rely on a graph comparing the price of TECO stock during the July 1, 2014 to July 13, 2015 to the SNL Energy stock index. CAPs assert that that the graph shows that the October 20, 2014 announcement of the agreement to sell TECO Coal had the effect of increasing TECO's price relative to the SNL Energy stock index and it subsequently maintained that higher relative price throughout the study period, demonstrating the continuing effect of the expected sale of TECO Coal on TECO's stock price.

503. We continue to disagree with these contentions. Although the October 20, 2014 announcement had an immediate effect on the price of TECO stock, we find that there is insufficient evidence that the announcement continued to have a sufficient effect on TECO's stock during the January to June 2015 study period to justify excluding TECO from the proxy group. In the first place, there is no evidence that the average risk profile of the companies reflected in the SNL Energy stock index is comparable to TECO's risk profile. The SNL Energy stock index "[i]ncludes all publicly traded (NYSE, NYSE MKT, NASDAQ, OTC) Electric, Gas, Diversified, and Merchant companies in SNL's coverage universe."[990] About half the companies tracked are midstream gas and oil pipeline companies, and thus the SNL Energy stock index is more exposed to risks associated with changes in natural gas and crude oil commodity prices than an electric utility with some local gas distribution business such as TECO. As a result, there has been no showing that a comparison of how TECO stock performed versus the SNL Energy stock index provides any meaningful information as to how the announcement of the sale of TECO Coal may have affected TECO's stock price during the first half of 2015.

504. In contrast to CAPs, MISO TOs provided at the hearing a graph comparing the price of TECO's stock with the Dow Jones Utility Index from November 1, 2014 to June 30, 2015.[991] That graph shows TECO's stock moving in virtual lockstep with the Dow Jones Utility Index. During periods when the Dow Jones Utility Index increased, the price of TECO stock almost invariably also increased; similarly, when the Dow Jones Utility Index decreased, the price of TECO stock almost invariably also decreased. As CAPs point out, the Presiding Judge was concerned that the MISO TOs' graph used different scales to display the prices of TECO stock and the Dow Jones Utility Index, and

[989] Ex. JCI-100 at 54-55 (I).

[990] Ex. JCI-10 at 271.

[991] Ex. MTO-23 at 99, Figure 1.

he asserted that if the same scale had been used to display both prices, the graph would have shown TECO stock prices increasing at a somewhat faster rate than the Dow Jones Utility Index.[992] However, in their reply brief in response to the Briefing Order, the MISO TOs have provided a revised graph comparing the TECO stock prices with the Dow Jones Utility Average, but using the same scale for both.[993] The revised graph continues to show TECO's stock moving in virtual lockstep with the Dow Jones Utility Index. CAPs' witness, Mr. Solomon, asserts that in late January/early February 2015, TECO's stock price was up approximately 20 percent compared to July 2014.[994] However, MISO TOs' revised graph shows a similar increase in the Dow Jones Utility Index. As MISO TOs' witness, Mr. McKenzie states, the revised graph indicates that there is no indication of systemic distortion in TECO's stock prices, relative to broader trends for the utility industry.[995] In fact, the revised graph shows, if anything, that during the latter part of the study period, the price of TECO stock declined at a slightly faster rate than the Dow Jones Utility Index did during that period, in further contradiction to CAPs' assertion that the TECO Coal sale announcement caused the price of TECO stock to increase during the study period, thus depressing its dividend yield.

505. Moreover, as the Commission pointed out in Opinion No. 551, TECO Coal represents less than 1.5 percent of TECO's total market capitalization.[996] We continue to find that the attempted sale of TECO coal appears too small relative to the size of the company to be responsible for significant changes in TECOs' stock price.

506. In addition, we are not persuaded by Mr. Solomon's argument disputing the Commission's determination, in Opinion No. 551, affirming the Initial Decision's finding that TECO's potential sale of TECO Coal had little impact on its projected growth rates. Opinion No. 551 pointed out that IBES's projected growth rates for TECO steadily increased throughout the first five months of the six-month study period, even as the

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[992] See Initial Decision (I), 153 FERC ¶ 61,027 at P 105. The Presiding Judge stated that while the TECO stock prices on the graph vary by 35.2 percent, the Dow Jones Utility Index varies by only 25.9 percent.

[993] MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (I) at 129. In the revised graph, both TECO stock prices and the Dow Jones Utility Average vary by 25 percent.

[994] Ex. JCI-100 at 57.

[995] *Id*. at 128-129.

[996] Ex. MTO-23 at 99 (valuing TECO Coal using the most recent non-contingent purchase price for the attempted sale to Cambrian).

prospects for selling TECO Coal steadily deteriorated.[997] If the potential sale of TECO Coal was a significant factor affecting TECO's DCF inputs, we would anticipate at least some decline in the expected growth rate as the prospects for a sale deteriorated between February and June, 2015. Instead, TECO's expected growth rate first increased from 6.43 percent in January 2015, to 7.08 percent in February, and to 9.20 percent in March, and held steady through June. CAPs point out that TECO's IBES growth projection fell to 7.68 percent in July, which was 152 basis points below the 9.20 percent growth projection in March, and the Commission used the 7.68 percent growth projection in its DCF analysis. CAPs suggest that the declining prospects for the sale of TECO Coal contributed to this decline. However, the 7.68 IBES growth projection in July was still above the January IBES growth projection of 6.43 percent and the February IBES growth projection of 7.08 percent, and thus simply returned TECO's growth projection to approximately the same level as at the start of the January to June 2015 study period. In short, the record simply does not suggest that the potential sale had much, if any, effect on the growth rate used in the DCF analysis. Mr. Solomon proffers no new evidence to the contrary.

507. Our merger screen seeks to exclude companies that are engaging in major mergers and acquisition activity. This attempted sale of TECO Coal does not reach this standard and appears to be the type of minor activity that occurs regularly in the course of business for utility holding companies. Accordingly, we deny rehearing of Opinion No. 551's holding that TECO should be included in the proxy group.

B. DCF Proxy Group and Analysis

508. In Opinion No. 551, the Commission affirmed the Presiding Judge's findings concerning how the two-step DCF analysis should be conducted. In this order, we have reaffirmed Opinion No. 551's approval of the Presiding Judge's DCF analysis, with one exception. In section V.C above, we have held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate used by the Presiding Judge. Accordingly, as shown in Appendix A to this order, we have revised the Presiding Judge's DCF analysis of the starting proxy group to reflect the revised calculation of the dividend yield.

509. We now turn to the issue of whether, for purposes of determining the DCF zone of reasonableness, any company in the starting proxy group should be excluded as a low- or high-end outlier. The Presiding Judge excluded three companies — Edison International, FirstEnergy Corporation (FirstEnergy), and Entergy Corporation (Entergy) — because

[997] Initial Decision (I), 153 FERC ¶ 63,027 at P 103.

their ROEs were less than 5.65 percent, which is 100 basis points above the average yield for public utility bonds rated Baa by Moody's.[998]

510. No party excepted to the Presiding Judge's ruling on this issue, and Opinion No. 551 accordingly adopted that ruling. However, as described above, in their brief responding to the Briefing Order, MISO TOs propose a revised low-end outlier test under which all companies whose ROEs are less than 254 basis points above the average yield for Baa utility bonds would be excluded from the proxy group. This revised test would exclude companies with ROEs below 7.19 percent.[999] Based on this revised test, MISO TOs propose to exclude from the DCF proxy group three companies in addition to the three that the Presiding Judge excluded. The additional three companies are Public Service Enterprise Group, Consolidated Edison, Inc., and OGE Energy Corp. The ROEs of those companies range from 7.23 percent to 7.28 percent. Although these ROEs exceed MISO TOs' 7.19 percent proposed threshold, MISO TOs nevertheless assert that they are sufficiently close to the threshold that an investor would consider the stock to yield essentially the same return as debt.[1000]

511. We reject MISO TOs' proposal to exclude Public Service Enterprise Group, Consolidated Edison, Inc., and OGE Energy Corp. from the DCF proxy group. In section X of this order, we rejected MISO TOs' proposed revised low-end outlier test. Instead, we adopted a revised low-end outlier test under which we exclude from the proxy group companies with ROEs that do not exceed the Baa bond yield by at least 20 percent of the risk premium from the CAPM analysis. In the First Complaint proceeding, the risk premium from the CAPM analysis is 9.12 percent**.** Twenty percent of that risk premium is 182 basis points. Adding 182 basis points to the 4.65 percent Baa bond yield produces a low-end outlier threshold in the First Complaint proceeding of 6.47 percent. Although that low-end outlier threshold is higher than the 5.65 percent low-end outlier threshold that the Presiding Judge applied, it does not exclude any additional companies from the proxy group. Public Service Enterprise Group and IDACORP, INC., both with ROEs of 7.23 percent, have the lowest DCF ROE of any company included in the proxy group. That ROE is well above the revised 6.47 percent low-end outlier threshold.

512. The Presiding Judge did not exclude any company from the DCF proxy group on the ground that it is a high-end outlier, nor does any participant seek to exclude any company on that ground. Under the high-end outlier test we have adopted in this order, we would, subject to the natural break analysis, exclude any DCF ROE that is more than 150 percent of the median of the starting proxy group DCF ROEs. In this case, the

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[998] *See id.* PP 66-67.

[999] MISO TOs Initial Br. (I), App.2 McKenzie Aff. (I) at 31.

[1000] *Id.* at 31 and n. 75.

median of the starting proxy group DCF ROEs, using the exclusions made by the Presiding Judge, is 8.68 percent. One-hundred-fifty percent of that median is 13.02 percent. TECO's DCF ROE of 11.37 percent is well below that amount. Accordingly, we do not exclude any company from the DCF proxy group as a high end-outlier. Based on this discussion, we conclude that the DCF zone of reasonableness is 7.23 percent to 11.37 percent.

C. CAPM Proxy Group and Analysis

513. In Opinion No. 551, the Commission affirmed the Presiding Judge's findings concerning how the CAPM analysis should be conducted. In this order, we have reaffirmed Opinion No. 551's approval of the Presiding Judge's CAPM analysis, with two exceptions related to the market risk premium. In section VII.C above, we have held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, instead of the average of the IBES and *Value Line* growth projections approved by the Presiding Judge.[1001] In addition, we have held that companies with negative ROEs or ROEs above 20 percent should be excluded from that analysis. Accordingly, we have revised the CAPM analysis of the starting proxy group approved by the Presiding Judge to reflect this revision.[1002]

514. We now turn to the issue of whether, for purposes of determining the CAPM zone of reasonableness, any company in the starting proxy group should be excluded from the CAPM proxy group as a low- or high-end outlier. The Presiding Judge did not exclude any company from the proxy group on these grounds, nor does any participant contend that any company is a low or high-end outlier. As discussed in the preceding section, we have determined that the low-end outlier threshold in the First Complaint proceeding is 6.37 percent. The companies in the starting proxy group with the lowest ROE are Duke Energy Corp. and Southern Company, both with ROEs of 7.80 percent. Because that ROE is well above the 6.37 percent low-end outlier threshold, we do not exclude any company from the CAPM proxy group as a low-end outlier.

515. Under the high-end outlier test we have adopted in this order, we would exclude from the CAPM proxy group any ROE that is more than 150 percent of the median of the starting proxy group CAPM ROEs. In this case, the median of the starting proxy group CAPM ROEs is 10.3 percent. One-hundred-fifty percent of that median is 15.45 percent.

[1001] Opinion No. 551, 156 FERC ¶ 61,234 at PP 169, 172.

[1002] The results of the CAPM analysis incorporating this revision and the other revisions and clarifications discussed above (i.e., use of the one-step DCF, size adjustment, and only IBES growth rates) are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (I), Attachment A to App. 2 at 6; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

The company with the highest CAPM ROE in the starting proxy group has an ROE of 13.09 percent, well below the 15.45 percent high-end outlier threshold. Accordingly, we do not exclude any company from the CAPM proxy group as a high end-outlier. Based on this discussion, we conclude that the CAPM zone of reasonableness is 7.80 percent to 13.09 percent.

D. Composite Zone of Reasonableness and FPA Section 206 Findings

516. Averaging the top and bottom of the DCF and CAPM zones of reasonableness determined above based on financial data for the first six months of 2015 produces a composite zone of reasonableness in the First Complaint proceeding of from 7.52 percent to 12.24 percent. The midpoint of that zone of reasonableness is 9.88 percent.

517. Having determined the composite zone of reasonableness based on financial data for the first half of 2015, we now turn to considering whether the MISO TOs' existing 12.38 percent ROE, which was determined based on financial data for the six months ending February 2002, may be found unjust and unreasonable pursuant to the first prong of FPA section 206. In section IV of this order, we have adopted the use of ranges of presumptively just and reasonable ROEs based on the risk profile of a utility or group of utilities to inform our decision whether an existing ROE has become unjust and unreasonable. Specifically, we have held that, for average risk utilities, the presumptively just and reasonable range is the quartile of the overall composite zone of reasonableness centered on the central tendency of the overall zone of reasonableness; for below average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of reasonableness; and for above average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness.

518. We find that, for purposes of determining the range of presumptively just and reasonable ROEs applicable to the MISO TOs, they must be treated as of average risk. In their initial brief in response to the Briefing Order, CAPs question whether the MISO TOs should be treated as of average risk.[1003] They assert that the Briefing Order erroneously stated that this is an undisputed fact because MISO TOs' credit ratings and risk profiles do not support a finding that the MISO TOs are of average risk. CAPs state that MISO TOs have study-period credit ratings ranging from S&P BB+ to A+ and contend that such a broad range of risk profiles cannot be described as average risk. They further argue that the risk profile of the MISO TOs as a group was disputed in both of the MISO ROE complaint proceedings. CAPs assert that CAPs introduced evidence of risk mitigation factors such as transmission rate incentives, high equity levels for some MISO TOs, and formula rates and MISO TOs introduced evidence of factors that increase risk, such as high CAPEX levels and evidence of risk purportedly not addressed

[1003] CAPs Initial Br. (I) at 80; CAPs Initial Br. (II) at 80.

by transmission rate incentives. CAPs also assert that the Commission fails to explain why ROEs that exceed the cost-based level by as much as one-eighth of the composite zone of reasonableness are presumptively just and reasonable for all of the MISO TOs' broad risk profiles.[1004]

519. In Opinion No. 551, the Commission disagreed with CAPs' contentions that the MISO TOs' formula rates and the high equity ratios of some MISO TOs reduce their risk profile as compared to the proxy group. Among other things, Opinion No. 551 held that our criteria for selecting members of the proxy group are intended to produce a proxy group made up of companies of similar risk. Those criteria include screens to ensure that the proxy group contains only utilities with similar credit ratings to the utility at issue. To the extent that a higher percentage equity in the capital structure reduces a utility's risk, as CAPs assert, then the utility's credit rating would be correspondingly higher than that of a utility with a typical capital structure.[1005] Opinion No. 551 also found that, to the extent formula rates reduce risk, they would, similar to the use of more equity in the capital structure, improve utility credit ratings. This would, in turn, affect the DCF proxy group because the credit screens require a proxy group of similarly rated utilities, diminishing the ROE produced by the DCF analysis.[1006] CAPs did not seek rehearing of these holdings in Opinion No. 551. Moreover, CAPs' evidence indicates that MISO TOs' average credit ratings are comparable to the averages for the proxy group. As MISO TOs point out, the average credit ratings that CAPs' witness Dr. Berry reports for the MISO TOs are within one notch of the average ratings for the proxy group, which does not indicate that MISO TOs are demonstrably less risky than the proxy group companies.[1007]

520. The Commission recognizes that, because the various MISO TOs have a relatively wide range of credit ratings, the proxy group in this case contains companies with a similarly wide range of credit ratings. However, as discussed in section XI of this order, we have held that the MISO TOs' ROE should be set at the midpoint of the zone of reasonableness, for the very reason that they are a diverse group with a variety of risk profiles, and the court has affirmed that policy. The midpoint fully considers the range of reasonable returns, because it is derived directly from the endpoints of the range.

[1004] CAPs Initial Br. (I) at 80-82; CAPs Initial Br. (II) at 80-82.

[1005] Opinion No. 551, 156 FERC ¶ 61,234 at P 288.

[1006] *Id*. P 297.

[1007] *See* MISO TOs Reply Br. (I), App. 2 McKenzie Reply Aff. (II) at 121; CAPs Initial Br. (I), Ex. OMS-105; CAPs Initial Br. (II), Ex. OMS-205.

521. Given that Commission policy is to set an RTO-wide ROE at the midpoint of the zone of reasonableness and the other record evidence regarding MISO TOs' risk profile, we conclude that MISO TOs must be treated as of average risk and that the range of presumptively reasonable ROEs for consideration in determining whether an existing RTO-wide ROE is unjust and unreasonable should be the quartile of the zone of reasonableness centered on the midpoint of the composite zone of reasonableness. In the First Complaint proceeding, that quartile is from 9.29 percent to 10.47 percent.[1008] ROEs within this range may be treated as presumptively just and reasonable, because they are closer to the 9.88 midpoint of the overall composite zone of reasonableness where we would set the ROE for a diverse group of average risk utilities, than to either: (1) the 8.70 midpoint of the lower half of that zone where we would set the ROE for a diverse group of below risk utilities; or (2) the 11.06 midpoint of the upper half of that zone where we would set the ROE for a diverse group of above risk utilities.[1009]

522. The MISO TOs' existing 12.38 percent is 191 basis above the range of presumptively just and reasonable ROEs for a diverse group of average risk utilities. Accordingly, it is treated as presumptively unjust and unreasonable. In fact, the existing 12.38 percent ROE is higher than the 12.24 percent top of the overall zone of reasonableness.[1010] It is thus clear that, in light of our estimate of the current cost of capital, the MISO TOs' existing ROE is well outside any possible range of potentially just and reasonable ROEs for the MISO TOs. We see no other evidence in the record, such as state ROEs, ROEs of non-utility companies, ROEs produced by other methodologies, non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, or testimony regarding the effects of rates on customers that would indicate that this is not the case. For example, the evidence in the record regarding state ROEs indicates that all state-authorized ROEs during the period April 1, 2013 through March 31, 2015 for integrated electric utilities providing generation, transmission, and distribution services ranged from 9.5 percent to 10.4 percent and that 87.34 percent of state-authorized ROEs for both integrated electric utilities and distribution-only electric utilities during that period were within this range.[1011] The fact that MISO TOs' 12.38

[1008] *See* Appendix C.

[1009] *Id.*

[1010] Although the 12.20 percent ATCLLC zone ROE is slightly below the top of the overall zone of reasonableness, it is 173 basis point above the range of presumptively reasonable ROEs established above. Therefore, our finding that MISO's existing 12.38 percent ROE is unjust and unreasonable applies equally to the 12.20 percent ATCLLC zone ROE.

[1011] *See, e.g.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 240.

percent ROE is 198 basis points above this range further demonstrates that MISO TOs' 12.38 percent ROE is unjust and unreasonable. In these circumstances, we find under the first prong of FPA section 206 that the MISO TOs' existing 12.38 percent ROE has become unjust and unreasonable.

523. Having found that the MISO TOs' existing ROE is unjust and unreasonable, we turn to the establishment of a just and reasonable replacement ROE under the second prong of FPA section 206. As discussed above, we have found that the midpoint of the composite zone of reasonable ROEs based on the most recent financial information in the record of the First Complaint proceeding is 9.88 percent. As discussed above, we find that MISO TOs are of average risk. Our policy is to set an RTO-wide ROE at the midpoint of the zone of reasonableness when the transmission owners receiving the RTO-wide ROE are of average risk. Accordingly, we find that the just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 9.88 percent. We therefore grant rehearing of Opinion No. 551 in part to require the MISO TOs to adopt a 9.88 percent ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32 percent ROE.

XVII. Complaint Specific Results: Second Complaint

A. Existing ROE for Purposes of Second Complaint

524. In the Briefing Order, the Commission stated that the issue to be addressed in the Second Complaint proceeding is whether the ROE established in the First Complaint remained just and reasonable based on financial data for the six-month period July to December 2015 presented by the participants at the hearing on the Second Complaint.[1012] However, certain parties dispute that the existing ROE to be analyzed for purposes of the Second Complaint is the ROE established in the First Complaint.

1. CAPs

525. CAPs argue that the Briefing Order errs in stating that the issue to be addressed in the Second Complaint proceeding is whether the ROE established in the First Complaint proceeding remained just and reasonable based on financial data for the six-month period from July to December 2015. CAPs contend that the existing ROE to which the July to December 2015 cost of equity should be compared is the 12.38 percent that was in effect from the time when the complaint was filed until September 28, 2016, when Opinion No. 551 was issued and reduced the ROE to 10.32 percent prospectively. They assert

[1012] *See* Briefing Order, 165 FERC ¶ 61,118 at P 61.

that this should be the case regardless of any relief that has been applied or will be applied as a remedy resulting from the First Complaint.[1013]

2. RPGI

526. RPGI argues that the Commission has not justified its interpretation that the "existing rate" for purposes of a section 206 complaint is the one that is determined in a prior proceeding. RGPI asserts that, in the context of successive complaint proceedings, that figure would be unknown when a second complaint is filed. RPGI states that this would present potential complainants with a choice of either awaiting the outcome of any pending 206 complaint to resolve the just and reasonable rate that would serve as the "existing rate" for purposes of framing a complaint, or file a complaint based on a rate that may not prove to be relevant under the Commission's proposed new ROE methodology. RPGI argues that the first choice foregoes any hope of receiving refunds for an unknown and potentially lengthy period of time, while the second choice is a gamble of investing in months or years of litigation that might prove fruitless or overtaken by events. RPGI asserts that the Commission's proposed approach would discourage the filing of complaints and that the Commission has not acknowledged or justified such a policy initiative.[1014]

3. MISO TOs

527. MISO TOs argue that the Briefing Order was correct in explaining that the existing base ROE for purposes of analyzing the Second Complaint is the ROE resulting from resolution of the First Complaint, as determined under the Commission's new ROE methodology. They assert that CAPs' objective in arguing that the 12.38 percent (or 12.20 percent) ROE should be the existing base ROE for purposes of the Second Complaint is to preserve a basis for refunds during the Second Complaint's refund period. MISO TOs contend that it would be illogical to evaluate the merits of a complaint against any rate other than the just and reasonable rate determined by the Commission from the preceding complaint. They argue that such an approach would lead to the meaningless outcome of forcing the Commission to re-examine a rate that it had already determined was unjust and unreasonable.[1015]

528. MISO TOs also assert that CAPs' interpretation of what the existing rate is for purposes of the Second Complaint would also violate section 206(b) of the FPA because

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[1013] CAPs Initial Br. (II) at 85-86.

[1014] RPGI Initial Br. (II) at 8-10.

[1015] MISO TOs Reply Br. (II) at 86-89.

it would, in this case, double the 15-month refund period in the statute. They argue that refunds arising by virtue of the Second Complaint, if any, will be based on the ROE determined in the First Complaint proceeding and the outcome of the First Complaint cannot legally serve as the predicate for refund liability for a period of thirty consecutive months, until the end of the Second Complaint refund period.[1016]

4. Commission Determination

529. FPA section 206(a) provides that "[w]henever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate . . . charged, or collected by any public utility for any transmission . . . subject to the jurisdiction of the Commission . . . is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate . . . to be thereafter observed and in force, and shall the fix the same by order." For purposes of deciding whether a rate charged by a public utility is unjust and unreasonable and determining a new just and reasonable rate "to be thereafter observed" pursuant to FPA section 206(a), we must assess whether the public utility's currently effective rate is unjust and unreasonable, not some earlier rate that may have been in effect when the complaint was filed but has now been superseded. Any new just and reasonable rate that we require "to be thereafter observed" pursuant to section 206(a) will replace the currently effective rate, not some previously effective rate. In other words, in order to determine a new rate to be thereafter observed, we must examine what the currently effective rate is because that is the rate that will need to be replaced if it is unjust and unreasonable. It therefore follows that it is the currently effective rate that must be found unjust and unreasonable.

530. The 12.38 percent ROE in effect when Arkansas Electric Cooperative et al. filed the Second Complaint on February 12, 2015 has been superseded. As discussed in the preceding section, in the First Complaint proceeding, we are requiring MISO TOs to reduce their ROE to 9.88 percent effective prospectively from September 28, 2016. Therefore, that is the MISO TOs' currently effective ROE as of today when we are deciding whether MISO TOs' ROE is unjust and unreasonable and should be modified prospectively pursuant to FPA section 206 in the Second Complaint proceeding. Accordingly, 9.88 percent is the ROE which we would have to find unjust and unreasonable under the first prong of FPA section 206, before we could require a new ROE "to be thereafter observed" pursuant to the second prong of FPA section 206. Moreover, as MISO TOs note, it would be illogical for the Commission to re-examine an ROE that it has already determined is unjust and unreasonable and that has been superseded by a new ROE.

531. We also agree with MISO TOs that interpreting the existing rate to be examined in the Second Complaint to be the now-superseded 12.38 percent ROE would effectively

[1016] *Id.* at 90-91.

extends the refund period in the First Complaint proceeding beyond the 15-month limitation in section 206. The Commission's decision in the First Complaint proceeding—i.e., that the 12.38 percent ROE is unjust and unreasonable—would effectively serve as the predicate for allowing refunds in the Second Complaint proceeding if that ROE continues to be unjust and unreasonable based on the data for the Second Complaint's study period, which would allow refunds to extend beyond the 15-month refund period limitation. In other words, if the Commission used the 12.38 percent ROE as the existing rate for purposes of the Second Complaint, then the Commission would be permitted to merely repeat its decision in the First Complaint that the 12.38 percent ROE is unjust and unreasonable and this same decision could serve as the predicate for ordering refunds again, which would effectively extend the statutory 15-month limitation.

532. Under the framework that we have adopted above for analyzing whether a currently effective ROE can be found unjust and unreasonable, we must first develop a composite zone of reasonableness based on the most recent financial data in the Second Complaint proceeding record (i.e., financial data for the period July to December 2015), and then determine whether the currently effective 9.88 percent ROE falls within, or outside, the appropriate range of presumptively just and reasonable ROEs. For the reasons discussed below, in this section we find that the 9.88 percent ROE does fall within the range of presumptively just and reasonable ROEs from the Second Complaint proceeding and we find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. Accordingly, we cannot find that ROE unjust and unreasonable or require a prospective modification of that ROE. Below in section XVIII, we address the issue of whether, having made that finding, we can nevertheless require refunds for the 15-month refund period when the MISO TOs' pre-existing 12.38 percent ROE was in effect.

B. Composition of Starting Proxy Group

533. As described above in paragraph 461 and in the Briefing Order,[1017] the Commission uses five screens for developing a proxy group. The first four screens listed above evaluate particular characteristics of the companies in question that do not vary depending upon the results of the DCF or CAPM analyses. Accordingly, those screens may be used to develop a starting group of proxy companies eligible for inclusion in the proxy group to be used for the purposes of the DCF and CAPM models. The low-end and high-end outlier tests must then be applied separately to the results of the DCF and CAPM models to determine the final DCF and CAPM proxy groups. First, we address the determination of the composition of the starting proxy group in the Second Complaint proceeding. We then apply the low-end and high-end outlier tests to the results of the

[1017] Briefing Order, 165 FERC ¶ 61,118 at PP 50-51.

DCF and CAPM analyses in order to determine the DCF and CAPM zones of reasonableness.

534. For purposes of determining the starting proxy group, the Presiding Judge determined that the DCF Study Period for calculating the zone of reasonableness should be the most recent six-month period for which there is financial data in the record, July to December 2015.[1018]

535. At the hearing in the Second Complaint proceeding, the participants considered 45 companies included in *Value Line*'s list of electric utilities for inclusion in the proxy group. The Presiding Judge found that all the participants agreed that 11 of these companies should be excluded, primarily because they failed the merger and acquisition screen.[1019] In addition, the Presiding Judge agreed with CAPs that Duke Energy Corporation and NextEra Energy Inc., should also be excluded from the proxy group because of merger and acquisition activity.[1020] This left a proxy group of 32 companies before application of any low-end or high-end outlier tests,[1021] No participant filed an exception to these findings by the Presiding Judge, and accordingly we affirm the Presiding Judge's findings as to the composition of the starting proxy group before application of the high-end and low-end outlier tests.

C. DCF Proxy Group and Analysis

1. Dividend Yield Data

a. Initial Decision (II)

536. The Presiding Judge stated that all participants in the Second Complaint proceeding calculated dividends for purposes of the DCF using the average yield approach. However, the Presiding Judge noted that the dividend yields that the participants calculated vary from one another. He explained that, while some witnesses

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[1018] Initial Decision (II), 155 FERC ¶ 63,030 at P 24.

[1019] *Id.* P 50. These companies were Black Hills Corporation; Cleco Corporation; Empire District Electric Company; Exelon Corporation; Hawaiian Electric Industrial, Inc.; ITC Holdings Corporation; MGE Energy, Inc.; Pepco Holdings, Inc.; Southern Company; TECO Energy, Inc.; and UIL Holdings.

[1020] *Id*. P 51.

[1021] The 32 companies (together with the ROEs for each company adopted by the Presiding Judge) are listed in Appendix I of the CAPs' initial post-hearing brief.

provided workpapers, their underlying data differs in ways that are difficult to check (e.g., monthly stock prices).[1022]

537. The Presiding Judge stated that these variances only mattered with respect to OGE Energy and PNM Resources, the total returns of which constitute, respectively, the low and high ends of the range of reasonableness. He stated that the CAPs and the MISO TOs calculate a 3.81 percent dividend yield for OGE Energy, while Trial Staff witness Mr. Keyton calculates a dividend yield 3.87 percent for the company. He further explained that the CAPs and the MISO TOs calculate a 2.92 percent yield for PNM, while Mr. Keyton calculates a 2.97 percent yield for the company.[1023]

538. The Presiding Judge stated that the Initial Decision "uses a consensus approach" that adopted the dividend yields calculated by CAPs and MISO TOs, as opposed to those calculated by Trial Staff's witness.[1024]

b. MISO TOs' Exceptions

539. In their Brief on Exceptions to Initial Decision (II), MISO TOs take exception to the Presiding Judge's decision to use the dividend yields for OGE Energy and PNM Resources calculated by CAPs and MISO TOs, as opposed to the higher dividend yields calculated by Trial Staff's witness.[1025] MISO TOs argue that Trial Staff's higher dividend yields for those two companies are based on its witness's reliance on the proxy companies' respective declared dividends in each month of the study period, and that this approach is consistent with Commission precedent that "'approv[es] the use of the most recent dividend declared by the relevant company to determine the 'indicated annual dividend' for each of the six months'" of the DCF study period.[1026] MISO TOs further assert that this approach is appropriate because "'[a] reasonable investor would factor a change in dividend . . . into its risk assessment of a company as of the date the dividend is

[1022] Initial Decision (II), 155 FERC ¶ 63,030 at P 55.

[1023] *Id.* P 56.

[1024] *Id.* P 57.

[1025] MISO TOs Br. on Exceptions at 44-45.

[1026] *Id.* at 45-46 (quoting Opinion No. 531, 147 FERC ¶ 61,234 at P 77 n.135).

declared, not the date it is paid.'"[1027] MISO TOs argue that the Presiding Judge offers no rationale for disregarding the declared dividends that Trial Staff's witness used.

c. Briefs Opposing Exceptions

540. CAPs argue that the Commission should deny MISO TOs' exceptions to the Presiding Judge's decision regarding the appropriate dividend yields to utilize for OGE and PNM. CAPs contend that the MISO TOs' own witness used the same dividends and dividend timing as the Presiding Judge in Initial Decision (II). CAPs assert that nowhere in the record have MISO TOs previously advocated for the use of the dividend increase timing used by Trial Staff's witness. CAPs further argue that MISO TOs have not demonstrated that the approach used by Trial Staff's witness is more appropriate than the approach that was used by both CAPs' witnesses and MISO TOs' witnesses.[1028]

541. CAPs contend that MISO TOs have provided no evidence or argument that the approach taken by Trial Staff's witness is uniquely accurate in reflecting the dividend increase timing that was known to the investors who set each study month's high and low stock prices. CAPs assert that the mere existence of slight variances in the witnesses' approaches does not prove that the Trial Staff witness' approach was more accurate. CAPs argue that MISO TOs had opportunities during the proceeding to present a basis supporting the approach taken by Trial Staff's witness, but they instead elected to present the dividend increase timing used by their own witness and did not disclose their disagreement with their own witness, or their preference for the approach used by Trial Staff's witness until well after the record closed.[1029]

542. CAPs contend that, as the record stands, it is at least equally possible that CAPs and MISO TOs witnesses, rather than Trial Staff's witness, took the more accurate and reasonable approach to the fine points of determining just when a dividend increase should be recognized in calculating a dividend yield. CAPs argue that, faced with a limited record, the Presiding Judge made a reasonable and supportable decision to utilize the dividend increase timing, and resulting dividend yields, presented by most of the witnesses, including the MISO TOs witness. CAPs conclude that the fact that MISO TOs

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[1027] *Id.* at 46 (quoting *Portland Natural Gas Transmission Sys.*, Opinion No. 524, 142 FERC ¶ 61,197, at P 321 (2013), *reh'g denied*, Opinion No. 524-A, 150 FERC ¶ 61,107 (2015)).

[1028] CAPs Br. Opposing Exceptions at 45-46.

[1029] *Id.* at 47.

now prefer Trial Staff witness' slightly higher dividend yields is no reason to overturn the Presiding Judge's determination.[1030]

543. OMS and JCA also opposed MISO TOs' exception on this issue. They argue that MISO TOs should not be allowed to file exceptions after the close of the record that are contrary to positions that their own witnesses took during litigation because it would deprive other participants of fair notice of their positions and an opportunity to adequately defend against them. OMS and JCA further note that Trial Staff itself did not file exceptions on this point, thereby tacitly accepting the approach adopted by the Presiding Judge in Initial Decision (II).[1031]

544. RPGI similarly opposes MISO TOs' exception on this point. RPGI argues that its witness, Mr. Parcell, calculated the exact same results for PNM Resources as MISO TOs' Witness McKenzie and two other witnesses, and the exact same results for OGE Energy as every other single witness except Trial Staff witness Mr. Keyton. RPGI asserts that MISO TOs failed to raise this matter in answering testimony, in cross examination or any time before filing exceptions despite having ample opportunity to do so.[1032]

545. RPGI also contends that MISO TOs' attempt to introduce their new "Appendix 2"—which provides revised IBES-based DCF returns for OGE Energy and PNM Resources, using the dividend yield calculations of Trial Staff's witness—into the record now without evidentiary foundation is unfair to the Commission and the parties. RPGI asserts that their witness cannot, at this point, offer any explanation or elaboration upon his decision to apply the dividend increase in the months that he did, nor can RPGI question MISO TOs' witness Mr. McKenzie about why he chose the same methodology as RPGI's witness.[1033]

d. Commission Determination

546. We agree with MISO TOs that Commission precedent requires changes in dividends to be reflected as of the date changes in dividends are declared, not as of the date that they are paid.[1034] We have explained that "the most recent declared dividend as

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[1030] *Id.* at 48.

[1031] OMS-JCA Br. Opposing Exceptions at 26-27.

[1032] RPGI Br. Opposing Exceptions at 33.

[1033] *Id.* at 33-34.

[1034] MISO TOs Br. on Exceptions at 45-46. *See also* Opinion No. 524, 142 FERC ¶ 61,197 at P 321 ("Trial Staff correctly used the declared date of January 21, 2011 for

of the end of each month during the six-month period" should be used when calculating the estimated dividend yield for purposes of the DCF analysis.[1035] Similarly, "the Commission [has] approved the use of the most recent dividend declared by the relevant company to determine the 'indicated annual dividend' for each of the six months."[1036] However, there is insufficient evidence for us to conclude that the OGE Energy and PNM Resources dividend yield calculations of Trial Staff's witness rely upon the dates that dividends were declared, while the calculations adopted by the Presiding Judge do not and instead rely upon the date on which dividends were paid, such that the latter calculations are inconsistent with Commission precedent. We agree with the Presiding Judge's determination that the differences between the dividend yield calculations of Trial Staff's witness and those of CAPs and MISO TOs' witnesses result from "underlying data [that] differs in ways that are difficult to check."[1037] Under these circumstances, we find that there is insufficient evidence to reverse the Presiding Judge's decision to adopt the dividend yield calculations that were used by a greater number of expert witnesses in this proceeding.

547. It does appear, as MISO TOs suggest, that Trial Staff's dividend yield calculations may have accurately factored in dividend changes as of the dates the dividends were declared, consistent with Commission precedent. For example, it appears that Trial Staff's witness increased the dividend in its calculations for PNM Resources to $0.88 per share for the month of December 2015,[1038] but CAPs' witness used a dividend of $0.80 per share for the month of December 2015, which was the rate that prevailed in the preceding months of the study period.[1039] Assuming the parties were relying on PNM Resource's December 10, 2015 declaration of a dividend increase to an indicated annual rate of $0.88 per share of common stock,[1040] then Trial Staff's calculations appear to

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the dividend. A reasonable investor would factor a change in dividend (here, an increase) into its risk assessment of a company as of the date the dividend is declared, not the date it is paid.").

[1035] Opinion No. 554, 158 FERC ¶ 61,050 at P 249.

[1036] Opinion No. 531, 147 FERC ¶ 61,234 at P 77 n.135.

[1037] Initial Decision (II), 155 FERC ¶ 63,030 at P 56.

[1038] Trial Staff Ex. S-6 at 240

[1039] Joint Customer Complainants Ex. JCI-8 at 5.

[1040] PNM Resources, PNM Resources Board Increases Dividend Payment, Declares Quarterly Common Stock Dividend, (Dec. 10, 2015),

include the appropriate dividend value for December 2015. However, it is unclear if the dividend values in Trial Staff's calculations were necessarily changed in response to this announcement or if the dividend values in the calculations of CAPs' witness remained unchanged because the dividend was not paid until after December 2015, or for some other reason. There is no clear and explicit explanation in the record of the reason for the changes in the inputs to the participants' dividend yield calculations. Accordingly, there is not a sufficient basis to conclude that the dividend yield calculations adopted by the Presiding Judge in Initial Decision (II) were inconsistent with Commission precedent and we affirm his decision on this issue.

548. Moreover, as OMS and JCA note, Trial Staff did not file exceptions to the Presiding Judge's decision on this issue.[1041] This creates further uncertainty as to the source of the differences between Trial Staff's dividend yield calculations and the calculations adopted by the Presiding Judge. In particular, it means that the record does not contain an explanation from Trial Staff addressing whether or not they agree with MISO TOs' contention that Trial Staff's calculations are consistent with Commission precedent, while those adopted by the Presiding Judge are not. The issue is further obscured by the fact that the Presiding Judge relied on the dividend yield calculations submitted by MISO TOs but now MISO TOs favor Trial Staff's calculations instead of their own. MISO TOs contrast Trial Staff's workpapers and those of CAPs' witness to suggest that Trial Staff's calculations should be used, but they do not address whether the calculations that they submitted themselves are inappropriate and if so, why. MISO TOs' dividend yield calculations were one of the two sets of calculations that the Presiding Judge stated constituted the "consensus approach" that he adopted. MISO TOs' failure to address why their own calculations are no longer appropriate further weakens the case for reversing the Presiding Judge's decision on this issue.

549. In light of the lack of clarity in the record as to why the dividend calculations from Trial Staff and those adopted by the Presiding Judge are different, we find that there is not a sufficient basis on which to reverse the Presiding Judge's decision to adopt the calculations that were used by a greater number of expert witnesses in this proceeding. Accordingly, we affirm the Presiding Judge's decision regarding the dividend yields for OGE Energy and PNM Resources to be used in the DCF analysis and deny MISO TOs' exceptions on this issue.

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https://www.prnewswire.com/news-releases/pnm-resources-board-increases-dividend-payment-declares-quarterly-common-stock-dividend-300191646.html.

[1041] *See* OMS-JCA Br. Opposing Exceptions at 27.

2. Outlier Tests and Final DCF Analysis

550. We affirm the Presiding Judge's DCF analysis in Initial Decision (II) in the Second Complaint proceeding, with one exception. As discussed above in section V.C, we have held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate used by the Presiding Judge. Accordingly, as shown in Appendix B to this order, we have revised the Presiding Judge's DCF analysis of the starting proxy group to reflect the revised calculation of the dividend yield.

551. We now turn to the issue of whether, for purposes of determining the DCF zone of reasonableness, any company in the starting proxy group should be excluded as a low- or high-end outlier. The Presiding Judge excluded Edison International, Entergy, FirstEnergy, and Public Service Enterprise Group.[1042]

552. As described above, in their brief responding to the Briefing Order, MISO TOs propose a revised low-end outlier test. In the Second Complaint proceeding, MISO TOs' proposed revised test would exclude all companies whose ROEs are less than 191 basis points above the average yield for Baa utility bonds from the proxy group. This revised test would exclude companies with ROEs below 7.32 percent.[1043] Based on this revised test, MISO TOs propose to exclude from the DCF proxy group three companies in addition to the three that the Presiding Judge excluded. The additional three companies are OGE Energy Corp., CenterPoint Energy, and IDACORP, Inc.[1044]

553. We reject MISO TOs' proposal to exclude CenterPoint Energy and IDACORP, Inc. from the DCF proxy group. In section X of this order, we rejected MISO TOs' proposed revised low-end outlier test. Instead, we adopted a revised low-end outlier test under which we exclude from the proxy group companies with ROEs that do not exceed the Baa bond yield by at least 20 percent of the risk premium from the CAPM analysis. In the Second Complaint proceeding, the risk premium from the CAPM analysis is 8.85 percent. Twenty percent of that risk premium is 177 basis points. Adding 177 basis

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[1042] Initial Decision (II), 155 FERC ¶ 63,030 at P 171 and P 174 n.75; *id.* P 54 ("This Initial Decision adopts the proxy group and the DCF results developed by the CAPs in Appendix I."); CAPs Reply Br. (II) at n.300 (citing CAPs, March 30, 2016 Initial Brief of the CAPs at 45 ("Applying the Commission's low-end outlier screen, CAPs witnesses eliminated four companies from their respective proxy groups: Edison International, FirstEnergy Corp., Public Service Enterprise Group, and Entergy Corp.").

[1043] MISO TOs Initial Br. (II), App. 2 at 27.

[1044] *Id.* at 27-28 and Attachment 3.

points to the 5.41 percent Baa bond yield produces a low-end outlier threshold in the Second Complaint proceeding of 7.18 percent. That low-end outlier threshold is higher than the 6.41 percent low-end outlier threshold that the Presiding Judge applied, and excludes one additional company from the proxy group—OGE Energy Corp.—whose DCF ROE is 6.75 percent.

554. The Presiding Judge did not exclude any company from the DCF proxy group on the ground that it is a high-end outlier, nor does any participant seek to exclude any company on that ground. Under the high-end outlier test we have adopted in this order, we would exclude any DCF ROE that is more than 150 percent of the median of the starting proxy group DCF ROEs. In this case, the median of the starting proxy group DCF ROEs is 8.70 percent.[1045] One-hundred-fifty percent of that median is 13.01 percent. PNM Resources' DCF ROE of 10.71 percent is well below that amount. Accordingly, we do not exclude any company from the DCF proxy group as a high end-outlier. Based on this discussion, we conclude that the DCF zone of reasonableness is 7.20 percent to 10.71 percent.[1046]

D. CAPM Proxy Group and Analysis

555. We affirm the Presiding Judge's CAPM analysis in Initial Decision (II) in the Second Complaint proceeding, with one exception related to the market risk premium. In section VII.C above, we have held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, which is consistent with the Presiding Judge's approach in Initial Decision (II).[1047] However, we have also held that companies with negative ROEs or ROEs above 20 percent should be excluded from that analysis. Accordingly, we have revised the CAPM analysis of the starting proxy group approved by the Presiding Judge to reflect this revision.[1048]

[1045] *See* Appendix C.

[1046] *Id.*

[1047] *See* Initial Decision (II), 155 FERC ¶ 63,030 at P 412.

[1048] The results of the CAPM analysis incorporating this revision and the other revisions and clarifications discussed above (i.e., use of the one-step DCF, size adjustment, and only IBES growth rates) are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (I), Attachment A to App. 2 at 6; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

556. We now turn to the issue of whether, for purposes of determining the CAPM zone of reasonableness, any company in the starting proxy group should be excluded from the CAPM proxy group as a low- or high-end outlier. The Presiding Judge did not exclude any company from the proxy group on these grounds, not does any participant contend that any company is a low or high-end outlier. As discussed in the preceding section, we have determined that the low-end outlier threshold in the Second Complaint proceeding is 7.18 percent. The company in the starting proxy group with the lowest ROE is Pacific Gas and Electric Company, with an ROE of 8.35 percent.[1049] Because that ROE is well above the 7.18 percent low-end outlier threshold, we do not exclude any company from the CAPM proxy group as a low-end outlier.

557. Under the high-end outlier test that we have adopted in this order, we would exclude from the CAPM proxy group any ROE that is more than 150 percent of the median of the starting proxy group CAPM ROEs. In this case, the median of the starting proxy group CAPM ROEs is 10.51 percent.[1050] One-hundred-fifty percent of that median is 15.77 percent. The company with the highest CAPM ROE in the starting proxy group has an ROE of 12.63 percent,[1051] well below the 15.77 percent high-end outlier threshold. Accordingly, we are not excluding any company from the CAPM proxy group as a high end-outlier. Based on this discussion, we conclude that the CAPM zone of reasonableness is 8.35 percent to 12.63 percent.[1052]

E. Composite Zone of Reasonableness and FPA section 206 Findings

558. Based on the findings above concerning the DCF and CAPM zones of reasonableness in the Second Complaint proceeding, we find that the composite zone of reasonableness based on the most recent financial data in the record of the Second Complaint proceeding is from 7.78 percent to 11.66 percent. The midpoint and the lower and upper midpoints of that zone of reasonableness are 9.72 percent, 8.72 percent, and 10.7 percent respectively. This results in a range of presumptively just and reasonable ROEs for the MISO TOs in the Second Complaint proceeding of 9.23 percent to 10.20 percent. As discussed above, the issue to be addressed in the Second Complaint is whether the ROE established in the First Complaint remained just and reasonable during the applicable test period as addressed by the evidence presented by the participants in

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[1049] *See* Appendix C; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

[1050] *See* Appendix C; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

[1051] *See* Appendix C; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

[1052] *See* Appendix C; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

the Second Complaint.[1053] The MISO TOs' 9.88 ROE established upon resolution of the First Complaint proceeding falls within the range of presumptively just and reasonable ROEs that applies in the Second Complaint. We find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. We see no evidence in the record, such as state ROEs, ROEs of non-utility companies, and other methodologies demonstrating serving to rebut this presumption. Accordingly, we cannot find that the MISO TOs' ROE established in the First Complaint proceeding and in effect as of the date of this order is unjust and unreasonable under the first prong of FPA section 206. For that reason, we cannot establish a new just and reasonable ROE in the Second Complaint proceeding to be in effect prospectively from the date of this order.

XVIII. Refunds in Second Complaint Proceeding

559. Our holding in the preceding section that we cannot establish a new just and reasonable ROE in the Second Complaint proceeding to be in effect prospectively raises the question of whether we can nevertheless order refunds for the Second Complaint's 15-month refund period. That period includes the 15 months from February 12, 2015 to May 11, 2016, and thus precedes the September 28, 2016 date when the 9.88 percent ROE established in the First Complaint proceeding took effect. Thus, during the entire 15-month refund period, the pre-existing 12.38 percent ROE was in effect.

A. CAPs

560. CAPs assert that section 206 provides for "refunds of any amounts paid . . . in excess of those which would have been paid under the just and reasonable rate" and through the 15-month refund period for the Second Complaint, the "amounts paid" by transmission customers were based on the 12.38 percent base ROE. They argue that, therefore, even assuming the First Complaint results in an ROE reduction and that reduced ROE is found to be just and reasonable based on the record in the Second Complaint proceeding, MISO transmission customers would continue to be entitled to refunds of the difference between the 12.38 percent rate they actually paid for the refund period and the reduced ROE found to be just and reasonable in the First Complaint and Second Complaint proceedings.[1054]

561. CAPs argue that the base ROE established as a result of the outcome of the First Complaint should be applied only to the prospective relief aspect of the Second Complaint. In other words, they contend that the base ROE determined in the First Complaint could result in denying prospective relief in the Second Complaint, but that

[1053] Briefing Order, 165 FERC ¶ 61,118 at P 61.

[1054] CAPS Reply Br. (II) at 10-11.

this should not necessarily result in a determination that the Second Complaint should yield no refunds during its applicable refund period. CAPs assert that, instead, refunds should apply to that period for the difference between the just and reasonable ROE determined in the Second Complaint proceeding (including if that remains the just and reasonable ROE determined in the First Complaint proceeding) and the 12.38 percent that was the existing base ROE for purposes of the Second Complaint.[1055]

562. CAPs contend that MISO TOs should not be allowed to keep revenues from the Second Complaint period, with no refund obligation, when those revenues reflect rates that incorporated a 12.38 percent ROE that was found to be unjust and unreasonable.[1056] They argue that this would be inconsistent with the principle that the FPA "meant to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."[1057]

563. CAPs also assert that the Commission erroneously contemplates using its "broad remedial authority" to correct "legal error" only with respect to the First Complaint outcome that will apply from September 28, 2016 going forward and not with respect to the Second Complaint. They argue that, to the extent that resolution of the Second Complaint results in a reduced ROE, the finally-determined ROE should be given effect from the date that the Commission would have been able to resolve the Second Complaint had Opinions Nos. 531 and 551 been properly decided. CAPs submit that the fair estimate of that date is the one estimated for that event in the Second Complaint Hearing Order, which was May 31, 2017. CAPs contend that the "legal error" doctrine should apply to the Second Complaint because its resolution was delayed by the legal errors in the vacated Opinion No. 531 and the time that the Commission has subsequently taken to process the remand and related proceedings.[1058]

B. MISO TOs

564. MISO TOs argue that, because the existing ROE resulting from resolution of the First Complaint remains just and reasonable for the study period applicable to the Second Complaint, the Second Complaint must be dismissed and therefore it cannot provide the

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[1055] *Id.* at 86-87.

[1056] *Id.* at 12-13.

[1057] *Id.* at 13 (citing *Atl. Refining Co. v. Pub. Serv. Comm'n*, 360 U.S. 378, 388 (1959)).

[1058] CAPs Initial Br. (II) at 87-89.

basis for refunds under section 206.[1059] MISO TOs contend that, because the Second Complaint must be dismissed, no action by the Commission in response to the Second Complaint can establish a rate to be "thereafter observed," which is a prerequisite to the Commission's ability to order refunds under FPA section 206. MISO TOs further argue that the Second Complaint cannot give rise to refunds because that would exceed the refund period limitation prescribed by section 206(b). They assert that, because refunds arising by virtue of the Second Complaint, if any, will be based on the ROE determined in the First Complaint proceeding, that outcome of that proceeding cannot legally serve as the predicate for refund liability for a period of thirty consecutive months from November 12, 2013 (the First Complaint refund effective date), through May 11, 2016 (the end of the Second Complaint refund period).[1060]

565. MISO TOs contend that CAPs' proposed May 31, 2017 date for relief resulting from the Second Complaint on the theory of "legal error" is moot because the Second Complaint will be dismissed based on the ROE established in the First Complaint. They argue that the ROE established in the First Complaint will be effective as of September 28, 2016, with refunds due for the 15-month refund period established in the First Complaint, and the Second Complaint will be dismissed, therefore the "legal error" theory provides no basis for relief in the Second Complaint proceeding. MISO TOs argue that, even if the Second Complaint would not be dismissed, the legal error theory does not apply to the Second Complaint because the Commission has not made any findings with respect to the Second Complaint and therefore there has been no Commission action in the Second Complaint proceeding that can be said to constitute legal error.[1061]

C. Commission Determination

566. As discussed above, the question on this issue is whether the Commission can order refunds of the 12.38 percent ROE that was in effect during the 15-month refund period in the Second Complaint proceeding despite the fact that the Commission is not granting any prospective relief with respect to the 9.88 percent ROE that is in effect as of the date we are acting on the Second Complaint.

567. Resolution of this issue requires the Commission to determine the extent of the refund authority granted the Commission by the following language of FPA section 206(b):

[1059] MISO TOs Reply Br. (II) at 87-88.

[1060] *Id.* at 89-90.

[1061] *Id.* at 91-93.

> At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided,* That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding.[1062]

568. As discussed below, we find that the Commission cannot order refunds in the Second Complaint proceeding because of the limits of our statutory authority under FPA section 206. The language of section 206(b) states that "[a]t the conclusion of any proceeding under this section" the Commission may order refunds for amounts paid during the 15-month refund period in excess of "what would have been paid under" the just and reasonable rate that "the Commission orders to be thereafter observed and in force." We interpret this language to mean that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding—i.e., the Commission sets a new just and reasonable rate which it "orders to be thereafter observed and in force." Here, as discussed above, we cannot find the 9.88 percent ROE in effect as of the date we are acting on the Second Complaint to be unjust and unreasonable and therefore we are not ordering any new just and reasonable rate "to be thereafter observed and in force." Having not ordered a new just and reasonable rate to be thereafter observed, there are no "amounts paid . . . in excess of" that rate that the Commission can order to be refunded.

569. In addition, we find that ordering refunds in the Second Complaint proceeding despite the fact that we are granting no prospective relief would exceed the statutory authority granted to us in FPA section 206 because it would effectively extend the 15-month refund period for the First Complaint. Section 206 explicitly limits the length of time that public utilities may be subject to potential refunds as a result of a Commission determination in a proceeding to 15 months after the refund effective date in that

[1062] 16 U.S.C. § 824e(b) (2018).

proceeding. Moreover, Congress indicated that the 15-month refund period was intended to limit the refund exposure of public utilities.[1063] Here, in the First Complaint proceeding, we have found the MISO TOs' pre-existing 12.38 percent ROE unjust and unreasonable and ordered that ROE reduced to 9.88 percent effective September 28, 2016 and ordered refunds for the November 12, 2013 to February 11, 2015 15-month refund period in the First Complaint proceeding. In the Second Complaint proceeding, we are not granting any prospective relief and allowing the 9.88 percent ROE determined in the First Complaint proceeding to continue. Accordingly, we find that ordering refunds in the Second Complaint proceeding on the basis of our ROE determination in the First Complaint proceeding, would exceed our statutory authority under FPA section 206 because it would effectively extend the refund period in the First Complaint proceeding beyond the statutory 15-month limit.

570. Moreover, section 206(b) indicates that Congress contemplated the possibility that the Commission could order refunds for periods outside of a proceeding's 15-month refund period, but only provided for that possibility in one instance that is not applicable here. Specifically, section 206(b) provides that, if a proceeding is not concluded within 15 months after the refund effective date, the Commission may order refunds for periods beyond the 15-month period if "the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility." The statute provides only this one exception to the 15-month refund period limitation and that exception does not apply to the Second Complaint. Accordingly, because any refunds that would be ordered in the Second Complaint proceeding would be refunds that were triggered by the Commission's determination in the First Complaint proceeding, the 15-month refund period in that First Complaint proceeding would apply, and there is no exception in the statute that would allow the Commission to order refunds beyond the 15-month refund period in that proceeding, there having been no dilatory behavior by the MISO TOs in either proceeding. The existence of this single explicit exception to the 15-month refund period limitation also indicates that Congress contemplated the possibility that a complainant may not necessarily receive refunds to make it completely whole if the 15-month refund period has expired, for example if conclusion of a complaint proceeding takes longer than 15 months but the delay is not primarily because of dilatory behavior by the public utility. Accordingly, while it may appear unusual at first glance to evaluate a complaint on the basis of whether an existing base ROE remains just and reasonable, but then deny the refunds that would be owed if that ROE actually was in effect, the statute explicitly contemplates that even successful complainants may not be made completely whole by refunds.

[1063] S. Rep. No. 100-491, at 6 (1988) (describing the fifteen-month refund period as a limit on "the time period during which refund liability can accrue.").

571. In addition, the legislative history indicates that Congress was aware that section 206 proceedings typically required two years to resolve but nonetheless adopted only a 15-month refund period.[1064] This further indicates that Congress was aware that even successful complainants may not be made completely whole by the refunds provided for in section 206. This is also consistent with other language in the legislative history which provides that the 15-month period is intended limit a respondent's refund liability, without reference to the success or merits of a complaint. Specifically, the Senate Report on the Regulatory Fairness Act states that

> While giving FERC the discretionary authority to grant refunds, the Committee amendment in several respects limits the time period during which refund liability can accrue. In general, refunds may only be ordered for amounts paid in excess of lawful rates during the period within 15 months of the refund effective date.[1065]

572. This approach is consistent with Commission precedent. In *San Diego Gas & Electric*,[1066] the Commission stated that "Under FPA section 206, as amended by the Regulatory Fairness Act, upon instituting a proceeding under section 206, the Commission establishes a refund effective date and *may order refunds*, commencing with the refund effective date and for up to 15 months thereafter, *if it finds an existing rate to be unjust, unreasonable or unduly discriminatory or preferential*."[1067] As described in that case, the Commission can only order refunds if it finds an existing rate to be unjust, unreasonable or unduly discriminatory or preferential. We are not finding an existing rate to be unjust, unreasonable or unduly discriminatory or preferential in the Second Complaint proceeding and we cannot order refunds in that proceeding.

573. As a result, we will dismiss the Second Complaint and not order MISO TOs to make any refunds for the applicable 15-month refund period in that proceeding. In light of this determination, we find that CAPs' request that any relief that is granted in the Second Complaint be granted effective as of May 31, 2017 because of the legal error doctrine is moot. The ROE established in the First Complaint will be effective as of September 28, 2016, with refunds due for the 15-month refund period established in the

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[1064] *See id.* ("Resolution of section 206 proceedings requires two years on average.").

[1065] *Id.*

[1066] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 127 FERC ¶ 61,191 (2009).

[1067] *Id.* P 17 (emphasis added).

First Complaint, and the Second Complaint will be dismissed; therefore, no relief will be granted in the Second Complaint proceeding. In other words, dismissal of the Second Complaint means that there will be no refund obligation associated with the Second Complaint, thus the Commission need not determine the time period applicable to that refund obligation, and the legal error doctrine is inapplicable.

XIX. Conclusion

574. For the reasons discussed above, we adopt the revised methodology described above for determining whether an existing base ROE is unjust and unreasonable under the first prong of FPA section 206, and for determining a new just and reasonable replacement base ROE under the second prong of FPA section 206 when an existing ROE has been shown to be unjust and unreasonable. Applying this revised methodology to the First Complaint proceeding results in a finding that MISO TOs' 12.38 percent ROE, which is pending before us on rehearing of Opinion No. 551, is unjust and unreasonable, thus resulting in us granting the First Complaint, and finding that 9.88 percent is a just and reasonable replacement ROE for MISO TOs. Accordingly, we grant in part and deny in part rehearing of Opinion No. 551 and require the MISO TOs to adopt a 9.88 percent ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32 percent ROE. As a result, we require MISO TOs to provide refunds, with interest for the First Complaint proceeding's 15-month refund period from November 12, 2013 through February 11, 2015, as discussed in the body of this order.

575. Applying this revised methodology to the Second Complaint proceeding results in a finding that the MISO TOs' 9.88 percent ROE established in the First Complaint proceeding to be effective prospectively from September 28, 2016, remains just and reasonable. Accordingly, we affirm in part and reverse in part Initial Decision (II) in the Second Complaint proceeding, grant in part and deny in part the exceptions to Initial Decision (II) as discussed above, and dismiss the Second Complaint. As a result, we find that no refunds should be issued as a result of the resolution of the Second Complaint, as discussed above.

The Commission orders:

(A) Rehearing of Opinion No. 551 is granted in part and denied in part, as discussed in the body of this order.

(B) MISO TOs' base ROE is set at 9.88 percent with a total or maximum ROE including incentives not to exceed 12.24 percent, effective as of September 28, 2016, as discussed in the body of this order.

(C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2019), within thirty (30) days of the date of this order, for the 15-month refund period for the First Complaint from November 12,

2013 through February 11, 2015 and for the period from September 28, 2016 to the date of this order, as discussed in the body of this order.

(D) MISO and MISO TOs are directed to file a refund report detailing the principal amounts plus interest paid to each of their customers within forty-five (45) days of the date of this order.

(E) The Initial Decision in the Second Complaint proceeding is affirmed in part and reversed in part, as discussed in the body of this order.

(F) The Second Complaint is dismissed, as discussed in the body of this order.

By the Commission. Commissioner Glick is dissenting in part with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Line	Company	Unadjusted Dividend Yield	Short-Term	Long-Term	Composite Growth	Dividend Yield Adjustment	Adjusted Dividend Yield	DCF Results
			Yahoo! Finance	GDP		One-Step		
1	Public Service Enterprise Group	3.74%	2.95%	4.39%	3.43%	101.48%	3.80%	7.23%
2	Consolidated Edison, Inc.	4.14%	2.38%	4.39%	3.05%	101.19%	4.19%	7.24%
3	OGE Energy Corp.	3.09%	4.00%	4.39%	4.13%	102.00%	3.15%	7.28%
4	IDACORP Inc.	3.04%	4.00%	4.39%	4.13%	102.00%	3.10%	7.23%
5	PPL Corporation	4.39%	2.23%	4.39%	2.95%	101.12%	4.44%	7.39%
6	CenterPoint Energy, Inc.	4.69%	1.91%	4.39%	2.74%	100.96%	4.73%	7.47%
7	Westar Energy Inc.	3.74%	3.40%	4.39%	3.73%	101.70%	3.80%	7.53%
8	Portland General Electric Co.	3.11%	4.70%	4.39%	4.60%	102.35%	3.18%	7.78%
9	DTE Energy Co.	3.38%	4.51%	4.39%	4.47%	102.26%	3.46%	7.93%
10	PG&E Corp.	3.39%	4.71%	4.39%	4.60%	102.36%	3.47%	8.07%
11	SCANA Corp.	3.91%	4.30%	4.39%	4.33%	102.15%	3.99%	8.32%
12	The Southern Co.	4.62%	3.32%	4.39%	3.68%	101.66%	4.70%	8.37%
13	Xcel Energy Inc.	3.68%	4.69%	4.39%	4.59%	102.35%	3.77%	8.36%
14	NorthWestern Corp.	3.60%	5.00%	4.39%	4.80%	102.50%	3.69%	8.49%
15	Duke Energy Corp.	4.05%	4.49%	4.39%	4.46%	102.25%	4.14%	8.60%
16	American Electric Power Co. Inc.	3.68%	5.08%	4.39%	4.85%	102.54%	3.77%	8.62%
17	NextEra Energy, Inc.	2.94%	6.27%	4.39%	5.64%	103.14%	3.03%	8.68%
18	Vectren Corp.	3.46%	5.50%	4.39%	5.13%	102.75%	3.56%	8.69%
19	Alliant Energy Corp.	3.50%	5.45%	4.39%	5.10%	102.73%	3.60%	8.69%
20	Avista Corp.	3.93%	5.00%	4.39%	4.80%	102.50%	4.03%	8.82%
21	Pinnacle West Capital Corp.	3.74%	5.30%	4.39%	5.00%	102.65%	3.84%	8.84%

22	Empire District Electric Co.	4.12%	5.00%	4.39%	4.80%	102.50%	4.22%	9.02%
23	Dominion Resources, Inc.	3.58%	5.89%	4.39%	5.39%	102.95%	3.69%	9.08%
24	Eversource Energy (Northeast Utilities)	3.27%	6.60%	4.39%	5.86%	103.30%	3.38%	9.24%
25	El Paso Electric Co.	3.01%	7.00%	4.39%	6.13%	103.50%	3.12%	9.25%
26	Ameren Corp.	3.91%	5.85%	4.39%	5.36%	102.93%	4.02%	9.39%
27	CMS Energy Corp.	3.35%	6.73%	4.39%	5.95%	103.37%	3.46%	9.41%
28	ALLETE Inc.	3.85%	6.00%	4.39%	5.46%	103.00%	3.97%	9.43%
29	Sempra Energy	2.59%	7.93%	4.39%	6.75%	103.97%	2.69%	9.44%
30	Great Plains Energy, Inc.	3.65%	6.37%	4.39%	5.71%	103.19%	3.77%	9.48%
31	Black Hills Corp.	3.28%	7.00%	4.39%	6.13%	103.50%	3.39%	9.52%
32	Otter Tail Corp.	4.06%	6.00%	4.39%	5.46%	103.00%	4.18%	9.65%
33	Exelon	3.64%	6.81%	4.39%	6.00%	103.41%	3.76%	9.77%
34	PNM Resources	2.85%	8.56%	4.39%	7.17%	104.28%	2.97%	10.14%
35	UIL Holdings	3.59%	7.79%	4.39%	6.66%	103.90%	3.73%	10.39%
36	ITC Holdings Corp.	1.76%	11.66%	4.39%	9.24%	105.83%	1.86%	11.10%
37	TECO Energy	4.61%	7.68%	4.39%	6.58%	103.84%	4.79%	11.37%
38	Unitil Corp.	Merger						
39	MGE Energy	Merger						
40	Edison International	2.66%	0.37%	4.39%	1.71%	100.19%	2.66%	4.37%
41	FirstEnergy Corp.	3.97%	-0.64%	4.39%	1.04%	99.68%	3.96%	4.99%
42	Entergy Corp.	4.21%	-0.48%	4.39%	1.14%	99.76%	4.20%	5.34%

Moodys Baa Utility Bonds	4.65%
Low With Outlier Test	7.23%
High with Outlier Test	11.37%
Midpoint	9.30%
Median Including Utilities Excluded with Outlier Test	8.68%
High-End Outlier Test	13.02%
Low-End Outlier Test	6.47%

Appendix B

Line	Company	Unadjusted Dividend Yield	Short-Term Yahoo! Finance	Long-Term GDP	Composite	Dividend Yield Adjustment One-Step	Adjusted Dividend Yield	DCF Results
19	PNM Resources, Inc.	2.92%	9.30%	4.35%	7.65%	104.65%	3.06%	10.71%
23	Sempra Energy	2.84%	9.35%	4.35%	7.68%	104.68%	2.97%	10.66%
25	WEC Energy Group, Inc.	3.58%	7.55%	4.35%	6.48%	103.78%	3.72%	10.20%
15	NorthWestern Corp.	3.61%	6.81%	4.35%	5.99%	103.41%	3.73%	9.72%
16	Otter Tail Corp.	4.05%	6.00%	4.35%	5.45%	103.00%	4.17%	9.62%
3	Ameren Corporation	3.96%	6.00%	4.35%	5.45%	103.00%	4.08%	9.53%
11	El Paso Elec. Co.	3.20%	7.00%	4.35%	6.12%	103.50%	3.31%	9.43%
7	CMS Energy Corp.	3.36%	6.72%	4.35%	5.93%	103.36%	3.47%	9.40%
12	Eversource Energy	3.39%	6.57%	4.35%	5.83%	103.29%	3.50%	9.33%
1	ALLETE, Inc.	4.16%	5.00%	4.35%	4.78%	102.50%	4.26%	9.05%
2	Alliant Energy	3.72%	5.55%	4.35%	5.15%	102.78%	3.82%	8.97%
9	Dominion Resources, Inc.	3.72%	5.49%	4.35%	5.11%	102.75%	3.82%	8.93%
17	PG&E Corp.	3.50%	5.80%	4.35%	5.32%	102.90%	3.60%	8.92%
5	Avista Corp.	3.98%	5.00%	4.35%	4.78%	102.50%	4.08%	8.86%
18	Pinnacle West Capital Corp.	3.92%	4.95%	4.35%	4.75%	102.48%	4.02%	8.77%
21	PPL Corp.	4.67%	3.74%	4.35%	3.94%	101.87%	4.76%	8.70%
10	DTE Energy Co.	3.75%	5.00%	4.35%	4.78%	102.50%	3.84%	8.63%
13	Great Plains Energy	3.83%	4.80%	4.35%	4.65%	102.40%	3.92%	8.57%
22	SCANA Corp.	3.90%	4.45%	4.35%	4.42%	102.23%	3.99%	8.40%
4	Amer. Elec. Power Co., Inc.	3.84%	4.47%	4.35%	4.43%	102.24%	3.93%	8.36%
27	Xcel Energy, Inc.	3.68%	4.68%	4.35%	4.57%	102.34%	3.77%	8.34%
24	Vectren Corp.	3.10%	5.00%	4.35%	4.78%	102.50%	3.18%	7.96%
20	Portland General Electric Co.	3.33%	4.11%	4.35%	4.19%	102.06%	3.40%	7.59%
8	Consol. Edison, Inc.	4.08%	2.95%	4.35%	3.42%	101.48%	4.14%	7.56%
26	Westar Energy Inc.	3.70%	3.50%	4.35%	3.78%	101.75%	3.76%	7.55%
14	IDACOPR, Inc.	3.03%	4.00%	4.35%	4.12%	102.00%	3.09%	7.21%
6	CenterPoint Energy, Inc.	5.47%	0.40%	4.35%	1.72%	100.20%	5.48%	7.20%
28	OGE Energy Corp.	3.81%	2.17%	4.35%	2.90%	101.09%	3.85%	6.75%
31	Public Service Enterprise Group							6.28%
30	FirstEnergy Corp.							5.38%
29	Edison International							3.92%

32	Black Hills Corp.	Merger						
33	Cleco Corp.	Merger						
34	Duke Energy Corp.	Merger						
35	Empire District	Merger						
36	Exelon Corp.	Merger						
37	Hawaii Elec. Ind. Inc.	Merger						
38	ITC Holdings	Merger						
39	NextEra Energy Inc.	Merger						
40	Pepco Holdings Inc.	Merger						
41	Southern Co.	Merger						
42	TECO Energy Inc.	Merger						
43	UIL Energy	Merger						

Moodys Baa Utility Bonds	5.41%
Low With Outlier Test	7.20%
High with Outlier Test	10.71 %
Midpoint	8.95%
Median Including Utilities Excluded with Outlier Test	8.70%
High-End Outlier Test	13.05 %
Low-End Outlier Test	7.18%

Appendix C

MISO I	DCF Zone			Lower Zone		Middle Zone		Upper Zone			Low-End Test	High-End Test
	Lower	Upper	1/8 Range	Lower	Upper	Lower	Upper	Lower	Upper	Median	(5)	(6)
DCF (1)	7.23%	11.37%	0.52%	7.75%	8.79%	8.79%	9.82%	9.82%	10.86%	8.65%	6.47%	12.98%
CAPM (2)	7.80%	13.09%	0.66%	8.46%	9.78%	9.78%	11.11%	11.11%	12.43%	10.30%	6.47%	15.45%
Average	7.52%	12.24%	0.59%	8.11%	9.29%	9.29%	10.47%	10.47%	11.65%			
Midpoint	**9.88%**											

MISO II	DCF Zone			Lower Zone		Middle Zone		Upper Zone			Low-End Test	High-End Test
	Lower	Upper	1/8 Range	Lower	Upper	Lower	Upper	Lower	Upper	Median	(7)	
DCF (3)	7.20%	10.71%	0.44%	7.64%	8.52%	8.52%	9.39%	9.39%	10.27%	8.7%	7.18%	13.01%
CAPM (4)	8.35%	12.63%	0.54%	8.89%	9.96%	9.96%	11.03%	11.03%	12.10%	10.51%	7.18%	15.77%
Average	7.78%	11.67%	0.49%	8.26%	9.24%	9.24%	10.21%	10.21%	11.18%			
Midpoint	**9.72%**											

(1) See Appendix A
(2) See p 6 of Attachment A of Trial Staff Initial Brief in Docket No. EL14-12
(3) See Appendix B
(4) See p 6 of Attachment A of Trial Staff Initial Brief in Docket No. El15-45
(5) 4.65% Baa Bond Yield found in Order No. 551 + 20% x 9.12 CAPM Risk Premium
(6) 150% of the median
(7) 5.41% Baa bond from MISO II Initial Decision + 20% x 8.85 CAPM risk premium

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Association of Businesses Advocating Tariff Equity Docket No. EL14-12-003
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation Docket No. EL15-45-000
Mississippi Delta Energy Agency
Clarksdale Public Utilities Commission
Public Service Commission of Yazoo City
Hoosier Energy Rural Electric Cooperative, Inc.

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

(Issued November 21, 2019)

GLICK, Commissioner, *dissenting in part*:

1. Although I join most of today's order, I dissent in part because I disagree with the Commission's decision not to order refunds of rates that we all agree were unjust and unreasonable. I fully support the Commission's conclusion that the MISO Transmission

Owners' (MISO TOs) pre-existing 12.38 percent ROE was unjust and unreasonable and its decision to fix the new just and reasonable ROE at 9.88 percent. Hopefully these determinations will provide some much-needed certainty to all MISO stakeholders. That being said, I disagree with the Commission's refusal to order refunds of the unjust and unreasonable rates collected during the refund period for the second of the two complaints pending before us. The law permits us to order those refunds and I see no reason to deprive customers of the full protections afforded by the Federal Power Act (FPA).

* * *

2. It helps to have the basic facts in one place. On November 12, 2013, multiple parties filed a complaint (First Complaint) alleging that the MISO TOs' 12.38 percent ROE was unjust and unreasonable.[1] The Commission set the matter for hearing and established a refund effective date of November 12, 2013 (the date the First Complaint was filed),[2] meaning that the 15-month refund period for the First Complaint lasted until February 12, 2015.[3] On February 12, 2015, a different set of parties filed another complaint (Second Complaint) against the MISO TOs' ROE. The Commission again set the matter for hearing and established a refund effective date of February 12, 2015,[4] meaning that the 15-month refund period for the Second Complaint lasted until May 12, 2016. On December 22, 2015, an Administrative Law Judge issued an initial decision recommending that the Commission grant the First Complaint and establish a new just

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[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,129, at P 3 (2019) (Order). The authorized base ROE for the ATCLLC zone was 12.20 percent, but I will follow the Order's practice of referring to the MISO-wide ROE as 12.38. *Id.* P 3 & n.11. The overall ROE that the MISO TOs could earn—*i.e.*, the sum of the base ROE and any incentives—was capped at 15.96. *Id.*

[2] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014), *order on reh'g*, 156 FERC ¶ 61,060 (2016).

[3] As discussed further below, pursuant to the Regulatory Fairness Act, Pub. L. No. 100-473, § 2, 102 Stat 2299 (1988) (codified at 16 U.S.C. § 824e(b)), as part of any proceeding under section 206 of the FPA, the Commission shall establish a refund effective date and, at the conclusion of that proceeding, it may order refunds for the difference between an unjust and unreasonable rate in effect during the period up to 15 months following the refund effective date and the new just and reasonable rate fixed by the Commission.

[4] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (Second Complaint Rehearing Order).

and reasonable ROE.[5] On June 30, 2016, a second Administrative Law Judge issued an initial decision, this time on the Second Complaint, again finding the MISO TOs' ROE to be unjust and unreasonable and establishing a new just and reasonable ROE.[6] And on September 28, 2016, the Commission issued Opinion No. 551, which largely affirmed the initial decision on the First Complaint, finding that the MISO TOs' 12.38 percent ROE was unjust and unreasonable and establishing a new just and reasonable ROE of 10.32 percent.[7] That is where things stood when the United States Court of Appeals for the District of Columbia Circuit issued its decision in *Emera Maine v. FERC*,[8] which vacated the Commission's decision in Opinion No. 531—on which Opinion No. 551 was based.

3. Today's order responds to *Emera Maine* by granting rehearing of Order No. 551 and (1) establishing a new process for evaluating whether an existing ROE is unjust and unreasonable, (2) applying that process to these proceedings to find that the MISO TOs' 12.38 percent ROE was unjust and unreasonable, and then (3) setting a new just and reasonable ROE of 9.88 percent. I join my colleagues on all three determinations. Nevertheless, I dissent in part because today's order requires the MISO TOs to pay refunds only for the First Complaint, and not the Second Complaint, even though it is undisputed that the unjust and unreasonable 12.38 percent ROE was in effect for the entire refund period established for the Second Complaint. I see nothing in section 206(b) of the FPA that prevents us from providing MISO customers with relief from that unjust and unreasonable ROE.

4. Section 206(b) provides that, at the conclusion of a proceeding under section 206, "the Commission may order refunds of any amounts paid [during the 15-month refund period] in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force."[9] All that text requires is that the Commission

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[5] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015).

[6] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016).

[7] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234, at P 9 (2016).

[8] 854 F.3d 9 (D.C. Cir. 2017).

[9] 16 U.S.C. § 824e(b). The full text of the relevant portion of section 206(b) is:

> At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund

find that customers paid an unjust and unreasonable rate during the refund period and that the Commission identify a replacement just and reasonable rate, so that it can calculate refunds equal to the difference between the two rates. Both conditions are satisfied here.

5. After all, there is no dispute that all parties were on notice that the Commission would require refunds in the event that it found the existing 12.38 percent ROE unjust and reasonable.[10] And there similarly is no dispute among my colleagues that the MISO TOs' 12.38 percent ROE was unjust and unreasonable and substantially in excess of the 9.88 percent just and reasonable ROE that the Commission is establishing pursuant to section 206. Applying the plain text of section 206(b), I believe that the Commission had ample authority to order refunds pursuant to the Second Complaint and should have done so here.[11] In addition, interpreting Section 206(b) to permit refunds in this instance is both more consistent with the FPA's primary purpose of protecting consumers[12] and

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> effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided,* That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding.

[10] *Cf. La. Pub. Serv. Comm'n v. FERC*, 482 F.3d 510, 520 (D.C. Cir. 2007).

[11] The Commission relies on its decision in *San Diego Gas & Electric* for the proposition that it can only order refunds when it grants a particular complaint. Order, 169 FERC ¶ 61,129 at P 572 (quoting *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 127 FERC ¶ 61,191 (2009)). But the quoted language merely restates the statutory text (albeit embellished with italics) without shedding any light on the Commission's authority to order refunds for subsequent pancaked complaints, which was not at issue in that decision.

[12] *See, e.g.*, *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (9th Cir. 2004); *City of Chicago, Ill. v. FPC*, 458 F.2d 731, 751 (D.C. Cir. 1971) ("[T]he primary purpose of the Natural Gas Act is to protect consumers." (citing, *inter alia*, *City of Detroit v. FPC*, 230 F.2d 810, 815 (1955)); *see also* S. Rep. 100-491, 5-6 (1988) ("The Committee intends the Commission to exercise its refund authority under section 206 in a manner that furthers the long-term objective of achieving the lowest cost for consumers consistent with the maintenance of safe and reliable service.").

more equitable given that the only reason we are faced with this question is that the Commission did not act on the First Complaint in the 15-month period before the Second Complaint was filed.

6. The Commission, by contrast, reads into the text of section 206(b) a pair of implicit limitations on its refund authority. But neither limitation is as well-founded as today's order would have you believe. First, the Commission interprets the presence of the word "thereafter" in section 206(b) "to mean that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding."[13] In other words, if the Commission does not fix a new just and reasonable ROE pursuant to each pancaked complaint, then it cannot order refunds of unjust and unreasonable rates collected during the relevant refund periods. I believe that the "thereafter observed and in force" language is better read as a reference to the identical language in section 206(a).[14] Under my reading, all the "thereafter observed and in force" language does is clarify that the ceiling on the Commission's refund authority pursuant to section 206(b) is the difference between the rate in effect during the refund period and the just and reasonable rate that the Commission subsequently established pursuant to subsection 206(a).[15] Accordingly, where the Commission finds that the rate that prevailed in the refund period exceeded the just and reasonable rate, the Commission has the authority to order refunds for the difference. That straightforward interpretation has the unremarkable result of allowing the Commission to protect customers by ordering refunds for any duly established refund period in which a public utility collected a rate in excess of the just and reasonable rate.

7. That brings us to the Commission's second limitation. The Commission contends that ordering refunds for the Second Complaint would, in essence, be an end run around the 15-month limit on refunds established in section 206(b).[16] But the Commission has repeatedly held that the FPA permits successive or "pancaked" complaints and those complaints are "'entirely new proceeding[s]'" and not "'duplicative proceeding[s]

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[13] Order, 169 FERC ¶ 61,129 at P 568.

[14] *See* 16 U.S.C. § 824e(a) (requiring the Commission to establish a new just and reasonable rate to be "thereafter observed and in force" whenever it finds that an existing rate is unjust and unreasonable or unduly discriminatory or preferential).

[15] That interpretation makes even more sense when you consider that section 206(b) was added more than 50 years after section 206(a), which was part of the original FPA, and so it would have been necessary to clarify how the amendment worked in conjunction with the pre-existing language.

[16] Order, 169 FERC ¶ 61,129 at P 569.

intended solely to expand the amount of refund protection beyond 15 months.'"[17] Accordingly, under the Commission's own interpretation of section 206, ordering refunds for the Second Complaint is not an end run around the 15-month limit on the refund period, but rather is consistent with customers' right under the FPA to file multiple complaints under section 206.

8. It may be that allowing refunds for pancaked complaints creates undue and unfair uncertainty for public utilities. But those policy considerations should not—and, in my opinion, do not—control our interpretation of the text of section 206(b). Perhaps Congress should consider revising section 206 to prohibit pancaked complaints. But it is not our job to do Congress' work for it. Unless and until Congress amends the FPA to prohibit pancaked complaints, the Commission should not permit its dislike of pancaked complaints to deprive customers of the full protections provided by the FPA.

For these reasons, I respectfully dissent in part.

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Richard Glick
Commissioner

[17] Second Complaint Rehearing Order, 156 FERC ¶ 61,061 at P 33 (quoting *Southern Co. Servs. Inc*., 83 FERC ¶ 61,079, 61,386 (1998)).

171 FERC ¶ 61,154
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick, Bernard L. McNamee,
and James P. Danly.

Association of Businesses Advocating Tariff Equity
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

Docket No. EL14-12-004

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation
Mississippi Delta Energy Agency
Clarksdale Public Utilities Commission
Public Service Commission of Yazoo City
Hoosier Energy Rural Electric Cooperative, Inc.

Docket No. EL15-45-013

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

OPINION NO. 569-A

ORDER ON REHEARING

(Issued May 21, 2020)

1. On November 21, 2019, the Commission issued Opinion No. 569.[1] In that order, the Commission acted on the then-pending rehearing requests and the Initial Decision, as well the Order Directing Briefs,[2] in the above-captioned proceedings. In brief, Opinion No. 569 applied a revised methodology for analyzing the base return on equity (ROE) component of public utility rates under section 206 of the Federal Power Act (FPA) that used the discounted cash flow (DCF) model and capital-asset pricing model (CAPM), instead of only the DCF model, and established a range of presumptively just and reasonable ROEs based on the quartiles of the zone of reasonableness. Multiple parties request rehearing of Opinion No. 569.[3] In this order, we grant in part and deny in part the requests for rehearing.

2. In particular, in Opinion No. 569, the Commission used the DCF model and CAPM in its determinations under the first and second prongs of section 206, giving each model equal weight under both prongs, and did not use the expected earnings (Expected Earnings) or risk premium (Risk Premium) models, as proposed in the Briefing Order. In addition, the Commission used the ranges of presumptively just and reasonable ROEs in its analysis under the first prong of section 206, as the Commission proposed in the Briefing Order, used the high-end outlier test as proposed in the Briefing Order, used the Institutional Brokers' Estimate System (IBES) as the source of short-term earnings growth estimates in the DCF and CAPM, and used a revised low-end outlier test that eliminates DCF and CAPM proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium. In this order, we are granting rehearing of Opinion No. 569 to use the Risk Premium model under both prongs of our section 206 analysis, to give the short-term growth rate 80% weighting and the long-term growth rate 20% weighting in the two-step DCF model, to modify the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model[4] before any high or low-end outlier test is applied, subject to a "natural break" analysis, to consider the use of *Value Line* short-term earnings growth estimates in the CAPM in future proceedings, and to calculate the ranges

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[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019).

[2] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (Briefing Order).

[3] *See infra* PP 23-24.

[4] As noted below, the high-end outlier test only applies to the DCF model and CAPM because they utilize results of the relevant analysis applied to a proxy group, while the Risk Premium model is derived from actual ROEs.

of presumptively just and reasonable base ROEs by dividing the overall composite zone of reasonableness into equal thirds.

3. Applying this revised methodology to the facts of the November 12, 2013, complaint filed in Docket No. EL14-12-000 pursuant to section 206 (First Complaint), we review the Midcontinent Independent System Operator, Inc. (MISO) transmission-owning members' (MISO TOs) 12.38% base ROE that was the existing ROE reviewed in Opinion No. 551, which was pending on rehearing before the Commission when it issued Opinion No. 569, and continue to find that this base ROE is unjust and unreasonable. Having found that MISO TOs' 12.38% ROE is unjust and unreasonable, we then find that a just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 10.02%. As discussed further below, in the second section 206 complaint (Second Complaint) proceeding in Docket No. EL15-45-000, the ROE to be reviewed is the 10.02% base ROE established in the First Complaint proceeding that is effective prospectively from September 28, 2016—the date of the issuance of Opinion No. 551. Under the revised base ROE methodology applied in this order, the 10.02% base ROE that the Commission is reviewing for purposes of the Second Complaint proceeding falls within the applicable range of presumptively just and reasonable base ROEs, therefore, the Commission presumes it to be just and reasonable. As discussed below, we find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. Accordingly, we affirm the Commission's decision in Opinion No. 569 to dismiss the Second Complaint, and its finding that no refunds should be issued as a result of the resolution of that complaint.

I. Background

A. Opinion No. 531 *et seq.*

4. In Opinion No. 531, the Commission adopted certain changes to its use of the DCF methodology for evaluating and setting the Commission-allowed ROE for the New England transmission owners (New England TOs). In particular, the Commission elected to replace the "one-step" DCF model, which considers only short-term growth projections for a public utility, with a "two-step" model that considers both short- and long-term growth projections.[5] The Commission also departed from its typical practice of setting the just and reasonable ROE of a group of utilities at the midpoint of the zone of reasonableness. The Commission explained that evidence of "anomalous" capital

[5] *See generally Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co*., Opinion No. 531, 147 FERC ¶ 61,234, at PP 8, 32-41, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *rev'd, Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*).

market conditions, including "bond yields [that were] at historic lows," made the Commission "less confiden[t] that the midpoint of the zone of reasonableness . . . accurately reflects the [ROE] necessary to meet the *Hope* and *Bluefield* capital attraction standards."[6] The Commission therefore looked to four alternative benchmark models: three financial models—the Risk Premium model, CAPM, and Expected Earnings model[7]—as well as a comparison with the ROEs approved by state public utility commissions.[8] In considering those models, the Commission emphasized that it was not departing from its long-standing reliance on the DCF model, but rather relying on those models only to "inform the just and reasonable placement of the ROE within the zone of reasonableness established . . . by the DCF methodology."[9] Based on these alternative models, the Commission determined that an ROE of 10.57%, the midpoint of the upper half of the zone of reasonableness produced by the two-step DCF model, would be just and reasonable. Because that figure differed from New England TOs' existing 11.14% ROE, the Commission concluded that the existing base ROE had become unjust and unreasonable and it therefore set New England TOs' base ROE at 10.57%, pending a paper hearing concerning the long-term growth projection to use in the DCF analysis. Following that hearing, in Opinion No. 531-A the Commission reaffirmed its conclusion that New England TOs' existing ROE was unjust and unreasonable and that 10.57% was the just and reasonable ROE. The Commission required New England TOs to submit a compliance filing to implement their new ROEs effective October 16, 2014—the date of issuance of Opinion No. 531-A.

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[6] Opinion No. 531, 147 FERC ¶ 61,234 at PP 144-145 & n.285. "*Hope*" and "*Bluefield*" refer to a pair of U.S. Supreme Court cases that require the Commission "to set a rate of return commensurate with other enterprises of comparable risk and sufficient to assure that enough capital is attracted to the utility to enable it to meet the public's needs." *Boroughs of Ellwood City, Grove City, New Wilmington, Wampum, & Zelienople, Pa. v. FERC*, 731 F.2d 959, 967 (D.C. Cir. 1984) (citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*) and *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of W.V.*, 262 U.S. 679 (1923) (*Bluefield*)).

[7] As discussed further below, the Risk Premium model estimates cost of equity using the implied premium that provided over Baa-rated utility bonds by regulatory decisions and settlements. The CAPM derives the ROE through the risk premium observed from the risk premium of a DCF analysis of S&P 500 dividend-paying companies. The Expected Earnings model is a method of calculating the earnings that an investor expects to receive on the book value of a particular stock.

[8] Opinion No. 531, 147 FERC ¶ 61,234 at PP 147-149.

[9] *Id.* P 146.

B. Opinion No. 551 *et seq.*

5. On November 12, 2013, multiple complainants[10] filed the First Complaint in Docket No. EL14-12-000 pursuant to section 206 of the FPA, alleging, among other things, that the MISO TOs' base ROE reflected in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff was unjust and unreasonable.[11] At the time of the First Complaint, MISO TOs had a base ROE of 12.38% (except for the ATCLLC zone which had a 12.20% ROE),[12] and their total ROE (i.e., the base ROE plus any ROE adders approved by the Commission) was not permitted to exceed 15.96%. The Commission established the MISO TOs' preexisting 12.38% ROE in a 2002 decision.[13] That ROE was based on a DCF analysis using financial data for the

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[10] The complainants consist of a group of large industrial customers: Association of Businesses Advocating Tariff Equity (ABATE); Coalition of MISO Transmission Customers (Coalition of MISO Customers); Illinois Industrial Energy Consumers (IIEC); Indiana Industrial Energy Consumers, Inc. (INDIEC); Minnesota Large Industrial Group (MLIG); and Wisconsin Industrial Energy Group.

[11] The following MISO transmission owners were named in the First Complaint: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC (ATC); Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; METC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company; and Wolverine Power Supply Cooperative, Inc. Intervenor Xcel Energy Services Inc. did not join certain of the MISO TOs' pleadings in this proceeding, but generally supported the brief on behalf of respondents Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation.

[12] For the sake of clarity, we refer to this ROE of the MISO TOs as 12.38% in this order, without separately identifying that the ATCLLC zone had a 12.20% ROE. Our discussion and decisions with respect to the MISO TOs' 12.38% ROE also apply to the 12.20% ATCLLC ROE.

[13] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, *initial decision affirmed as to base ROE*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC

six-month period ending February 2002.[14] On October 16, 2014, the same date that the Commission issued Opinion No. 531-A, it set the First Complaint for hearing before an Administrative Law Judge and established a refund effective date of November 12, 2013.[15]

6. Following the hearing, the Presiding Judge issued an Initial Decision,[16] and the Commission subsequently issued Opinion No. 551.[17] In Opinion No. 551, the Commission calculated the just and reasonable ROE using the two-step DCF methodology from Opinion No. 531 and financial data for the period January 1 through June 30, 2015. The Commission affirmed the conclusions of Initial Decision (I), finding that the Presiding Judge correctly applied the two-step DCF analysis required by Opinion No. 531.[18] The Commission also affirmed the Presiding Judge's determination that, as in Opinion No. 531, there were anomalous capital market conditions such that the Commission had less confidence that the midpoint of the zone of reasonableness produced by a mechanical application of the DCF methodology satisfied the capital attraction standards of *Hope* and *Bluefield*.[19] The Commission found that the Presiding Judge reasonably considered evidence of alternative methodologies for determining the

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¶ 61,143 (2003), *order on remand*, 106 FERC ¶ 61,302 (2004). The ATCLLC zone base ROE of 12.20% was established as part of a settlement agreement that was filed with the Commission on March 26, 2004. In Docket No. ER04-108-000, the Commission approved the uncontested settlement. *Am. Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, app. A.

[15] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014) (MISO I Hearing Order), *order on reh'g*, 156 FERC ¶ 61,060 (2016) (MISO I Rehearing Order). In the MISO I Rehearing Order, the Commission denied requests for rehearing and clarification of the MISO I Hearing Order and clarified that non-public utility transmission owners are subject to the outcome of that proceeding. MISO I Rehearing Order, 156 FERC ¶ 61,060 at PP 47-48.

[16] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015) (Initial Decision (I)).

[17] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016) (affirming Initial Decision (I), 153 FERC ¶ 63,027).

[18] *See generally* Opinion No. 551, 156 FERC ¶ 61,234 at P 9.

[19] *Id.*

ROE and the ROEs approved by state regulatory commissions, for purposes of deciding to set the ROE at the central tendency of the upper half of the zone of reasonableness, setting the base ROE for MISO TOs at 10.32%.[20] The Commission required MISO TOs to submit a compliance filing to implement their new ROEs effective September 28, 2016, the date of Opinion No. 551, and to provide refunds for the November 12, 2013-February 11, 2015 refund period. Following the issuance of Opinion No. 551, numerous parties submitted requests for rehearing.

C. Second Complaint Against MISO TOs' ROE

7. On February 12, 2015, a new set of complainants[21] filed the Second Complaint in Docket No. EL15-45-000 also alleging that the MISO TOs' base ROE of 12.38% was unjust and unreasonable.[22] Relying on an updated two-step DCF analysis, the Second Complaint complainants argued that the base ROE should be no higher than 8.67%.[23] On

[20] *Id.*

[21] Complainants for the Second Complaint consist of: Arkansas Electric Cooperative Corporation (Arkansas Electric Cooperative); Mississippi Delta Energy Agency and its two members, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and Public Service Commission of Yazoo City of the City of Yazoo City, Mississippi; and Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier Cooperative).

[22] The following MISO transmission owners were named in the Second Complaint: ALLETE, Inc. (for its operating division Minnesota Power, Inc. and its wholly-owned subsidiary Superior Water Light, & Power Company); Ameren Illinois Company; Union Electric Company (identified as Ameren Missouri); Ameren Transmission Company of Illinois; ATC; Cleco Power LLC; Duke Energy Business Services, LLC; Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company, ITC Midwest LLC, and Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company-Minnesota; Northern States Power Company-Wisconsin; Otter Tail Power Company; and Southern Indiana Gas & Electric Company.

[23] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015) (MISO II Hearing Order), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (MISO II Rehearing Order).

June 18, 2015, the Commission established hearing procedures and set a refund effective date of February 12, 2015.[24]

8. Parties filed requests for rehearing of the MISO II Hearing Order, and on July 21, 2016, the Commission generally denied these rehearing requests.[25] Following the MISO II Hearing Order, the Presiding Judge issued the Initial Decision on June 30, 2016.[26] The Presiding Judge adopted a zone of reasonableness of 6.75% to 10.68% based on financial data for the period July 1, 2015 through December 31, 2015. The Presiding Judge also determined that the anomalous capital market conditions identified in Opinion No. 531 persisted and, after considering the alternative benchmark methodologies, that the just and reasonable ROE was 9.70%—halfway between the midpoint and the upper bound of the zone of reasonableness. The participants filed briefs on and opposing exception.

D. ***Emera Maine***

9. On April 14, 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its *Emera Maine* decision, vacating and remanding Opinion No. 531 *et seq*. As an initial matter, the D.C. Circuit was not persuaded by New England TOs' argument that an ROE within the DCF-produced zone of reasonableness could not be deemed unjust and unreasonable. The D.C. Circuit explained that the zone of reasonableness established by the DCF is not "coextensive" with the "statutory" zone of reasonableness envisioned by the FPA.[27] Accordingly, the D.C. Circuit concluded that the fact that New England TOs' existing ROE fell within the zone of reasonableness produced by the DCF did not necessarily indicate that it was just and reasonable for the purposes of the FPA.[28]

10. Nevertheless, the D.C. Circuit found that the Commission had not adequately shown that New England TOs' existing ROE was unjust and unreasonable. The D.C. Circuit explained that the FPA's statutory "zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE" and that whether a particular ROE is unjust and unreasonable depends on the "particular

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[24] MISO II Hearing Order, 151 FERC ¶ 61,219 at P 1.

[25] *See* MISO II Rehearing Order, 156 FERC ¶ 61,061.

[26] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016) (Initial Decision (II)).

[27] *Emera Maine*, 854 F.3d at 22-23.

[28] *Id.* at 23.

circumstances of the case."[29] Thus, the fact that New England TOs' existing ROE did not equal the just and reasonable ROE that the Commission would have set using the current DCF inputs did not necessarily indicate that New England TOs' existing ROE fell outside the statutory zone of reasonableness.[30] As such, the D.C. Circuit concluded that Opinion No. 531 "failed to include an actual finding as to the lawfulness of [New England TOs'] existing base ROE" and that its conclusion that their existing ROE was unjust and unreasonable was itself arbitrary and capricious.[31]

11. The D.C. Circuit also found that the Commission had not adequately shown that the 10.57% ROE that it set was just and reasonable. Although recognizing that the Commission has the authority "to make 'pragmatic adjustments' to a utility's ROE based on the 'particular circumstances' of a case," the D.C. Circuit nevertheless concluded that the Commission had not explained why setting the ROE at the upper midpoint was just and reasonable.[32] The D.C. Circuit noted, in particular, that the Commission relied on the alternative models and state-regulated ROEs to support a base ROE above the midpoint, but that it did not rely on that evidence to support an ROE at the upper midpoint.[33] Similarly, the D.C. Circuit noted that the Commission had concluded that a base ROE of 9.39%—the midpoint of the zone of reasonableness—might not be sufficient to satisfy *Hope* and *Bluefield* or to allow the utility to attract capital, but that the Commission had not similarly explained how a 10.57% base ROE was sufficient to meet either of those conditions. Because the D.C. Circuit found that the Commission had not pointed to record evidence supporting the specific point at which it set New England TOs' ROE, the

[29] *Id.* at 23, 26.

[30] *Id.* at 27 ("To satisfy its dual burden under section 206, FERC was required to do more than show that its single ROE analysis generated a new just and reasonable ROE and conclusively declare that, consequently, the existing ROE was per se unjust and unreasonable.").

[31] *Id.*

[32] *Id.* (quoting *FPC v. Nat. Gas Pipeline Co. of America*, 315 U.S. 575, 586 (1942)).

[33] *Id.* at 29 ("FERC's reasoning is unclear. On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57% base ROE.").

D.C. Circuit held that the Commission had not articulated the "rational connection" between the evidence and the rate that the FPA demands.[34]

12. Based on the D.C. Circuit's conclusion that the Commission had not met its burden either under the first or the second prong of section 206 of the FPA, it vacated and remanded Opinion No. 531 *et seq.*,[35] meaning that Opinion No. 531 is no longer precedential,[36] even though the Commission remained free to re-adopt those determinations on remand as long as it provided a reasoned basis for doing so.[37] The Commission relied extensively on its determinations in Opinion No. 531 in its order on the First Complaint (i.e., Opinion No. 551).

E. Briefing Orders

13. On October 16, 2018, the Commission issued an order proposing a methodology for addressing the issues that were remanded to the Commission in *Emera Maine* and established a paper hearing on whether and how this methodology should apply to the four complaint proceedings concerning New England TOs' ROE.[38] In the *Coakley* Briefing Order, the Commission proposed to change its approach to determining base ROE by giving equal weight to four financial models, instead of primarily relying on the DCF methodology. The Commission stated that evidence indicates that investors do not rely on any one model to the exclusion of others. Therefore, relying on multiple financial models made it more likely that the Commission's ROE determination would accurately reflect how investors make their investment decisions.

14. Specifically, the Commission proposed to rely on three financial models that produce zones of reasonableness—the DCF model, CAPM, and Expected Earnings model—to establish a composite zone of reasonableness. The zone of reasonableness produced by each model would be given equal weight and averaged to determine the composite zone of reasonableness.[39]

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[34] *Id.* at 28-30.

[35] *Id.* at 30.

[36] *Id.*

[37] *Id.*

[38] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order).

[39] *See id.* PP 16, 30.

15. The Commission also proposed a framework for using the composite zone of reasonableness in evaluating whether an existing base ROE remains just and reasonable. The Commission proposed that, in order to find a utility's existing ROE unjust and unreasonable under the first prong of section 206 of the FPA, its ROE must be outside a range of presumptively just and reasonable ROEs for a utility of its risk profile, absent additional evidence to the contrary. In other words, the Commission would dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile unless that presumption is sufficiently rebutted. The Commission explained that, by the same token, a finding that the existing ROE of a utility falls outside that range would support a holding that the ROE has become unjust and unreasonable, absent additional evidence to the contrary.[40]

16. The Commission explained that it would be appropriate to calculate the applicable ranges of presumptively just and reasonable ROEs based on a utility's risk profile because a utility's risk profile remains the "particular circumstance[]" most relevant to determining whether a point within a zone of reasonableness is a just and reasonable ROE for that utility.[41] The Commission further concluded that the "principal consideration for determining whether an existing ROE within the overall zone of reasonableness has become unjust and unreasonable is the risk profile of the utility or utilities for which the Commission is setting the ROE."[42]

17. The Commission proposed that the applicable range of presumptively just and reasonable ROEs for a utility should correspond to those points that are closer to the ROE that the Commission should set for that utility than to the ROE for a utility of a different risk profile.[43] For example, the Commission explained that it typically would be unjust and unreasonable for an average risk utility to receive an ROE that is closer to the ROE that would be just and reasonable for a utility of above- or below-average risk.[44] In particular, for average risk utilities, the Commission proposed that the presumptively just and reasonable range would be the quartile of the zone of reasonableness centered on the central tendency of the composite zone of reasonableness. For below average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of

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[40] *See id.* PP 16, 28.

[41] *Id.* P 24 (quoting *Emera Maine*, 854 F.3d at 23).

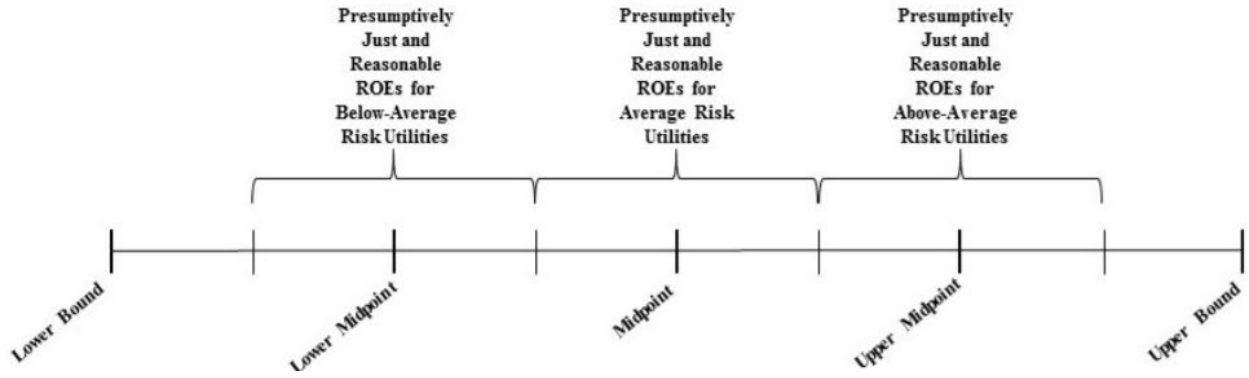
[42] *Id.* P 28.

[43] *Id.* P 27.

[44] *Id.* P 26.

reasonableness. For above average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness.[45] The Commission illustrated how these presumptively just and reasonable quartile ranges would be divided as follows:

Figure 1: Zone of Reasonableness Quartiles



18. For purposes of establishing a new just and reasonable base ROE when the existing base ROE has been shown to be unjust and unreasonable, the Commission proposed using the above three models, plus the Risk Premium model. The Risk Premium model produces a single numerical point rather than a range; therefore, the Commission did not propose to use it to establish a composite zone of reasonableness. The Commission proposed to determine a new just and reasonable ROE for average risk utilities by determining the midpoint/medians of each zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models and averaging those ROEs with the Risk Premium ROE, giving equal weight to each of the four figures.[46] The Commission

[45] *Id.*

[46] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 344 ("In determining the central tendency of the zone of reasonableness, the Commission has distinguished between cases involving an RTO-wide ROE and cases involving the ROE of a single utility (or pipeline). In cases involving an RTO-wide ROE, the Commission has held that the midpoint is appropriate. The Commission has reasoned that, because an RTO-wide ROE will apply to a diverse set of companies, the range of results becomes as important as the central value, and the midpoint fully considers that range, because it is derived directly from the endpoints of the range . . . By contrast, in cases involving a single utility, the Commission has held that using the median is appropriate, because the median 'is the most accurate measure of central tendency for a single utility of average risk.'") (citing *SoCal Edison*, 131 FERC ¶ 61,020, at P 91 (2010), *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013) (*S. Cal. Edison v. FERC*)); Briefing Order, 165 FERC ¶ 61,118 at n.40: "The Commission will continue to use the midpoint of the zone of reasonableness as the appropriate measure of central

proposed to use the midpoint/medians of the lower and upper halves of the zones of reasonableness to determine ROEs for below average and above average risk utilities, respectively, and average those ROEs with the Risk Premium ROE.[47]

19. On November 15, 2018, the Commission issued the Briefing Order in these proceedings. In that order, the Commission similarly established a paper hearing on whether and how the methodology proposed in the *Coakley* Briefing Order should apply to the two proceedings pending before the Commission involving MISO TOs' ROE.[48]

F. Opinion No. 569

20. On November 21, 2019, the Commission issued Opinion No. 569 in which it applied a revised methodology for analyzing existing base ROEs under section 206 of the FPA. The revised methodology applied in Opinion No. 569 did not use the Expected Earnings or Risk Premium models as was proposed in the Briefing Order, and instead used only the DCF model and CAPM in the Commission's determinations under the first and second prongs of section 206. The methodology applied in Opinion No. 569 gave equal weight to the DCF model and CAPM by averaging the top and bottom of the DCF and CAPM zones of reasonableness to produce a composite zone of reasonableness.[49] In addition, in Opinion No. 569, the Commission reaffirmed its use of a two-step DCF analysis that gives one-third weight to a long-term growth rate based on projected growth in gross domestic product (GDP).[50] The Commission also held that it would continue to rely exclusively on the IBES as the preferred source for the DCF short-term growth projection, absent compelling reasons otherwise.[51] The Commission further held that only the short-term growth rate should be used to calculate the (1+.5g) adjustment to dividend yield in the DCF analysis for the CAPM.[52]

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tendency for a diverse group of average risk utilities and the median as the measure of central tendency for a single utility."

[47] *Id.* P 17.

[48] *See* Briefing Order, 165 FERC ¶ 61,118 at P 1.

[49] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 37, 276.

[50] *Id.* PP 151-159.

[51] *Id.* P 133.

[52] *Id.* PP 98-100.

21. In Opinion No. 569, the Commission also adopted a specific CAPM methodology. First, the Commission adopted the use of the 30-year U.S. Treasury average historical bond yield over a six-month period as the risk free rate.[53] Second, the Commission held that the CAPM expected market return should be estimated using a forward-looking approach based on applying the DCF model to the dividend paying members of the S&P 500.[54] In addition, the Commission approved the use of a one-step DCF model using only short-term three to five-year growth projections for the DCF analysis of the dividend paying members of the S&P 500. The Commission also held that IBES should be the sole source of the short-term earnings growth estimates used in the DCF analysis that is part of the CAPM analysis[55] and that S&P 500 companies with growth rates that are negative or in excess of 20% should be screened from the DCF analysis.[56] Finally, the Commission held that the CAPM analysis should include a size premium adjustment.[57]

22. In addition to the above holdings concerning the DCF and CAPM models, the Commission also adopted a revised low-end outlier test that eliminates DCF and CAPM proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium.[58] The Commission also adopted the high-end outlier test that was proposed in the *Coakley* Briefing Order and the Briefing Order in these proceedings, which treats as high-end outliers any proxy company whose cost of equity estimated under the model in question is more than 150% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis.[59] The Commission also reaffirmed its use of the midpoint, rather than the median, as the measure of central tendency for ROEs that applied to groups of utilities.[60]

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[53] *Id.* P 238.

[54] *Id.* PP 260-273.

[55] *Id.* PP 274-276.

[56] *Id.* PP 267-268.

[57] *Id.* PP 296-303.

[58] *Id.* PP 19, 387-89.

[59] *See id.* PP 367-68, 375.

[60] *Id*. PP 409-413.

G. Requests for Rehearing

23. On December 23, 2019, the following parties to one or both of these proceedings filed requests for rehearing of Opinion No. 569: MISO TOs, the Complaint-Aligned Parties (CAP);[61] the Resale Power Group of Iowa (RPGI); Louisiana Public Service Commission (LPSC); Exelon Corporation (Exelon); Transource Energy, LLC (Transource Energy); and Ameren Services Company, on behalf of its transmission-owning public utility affiliates Ameren Illinois Company d/b/a Ameren Illinois, Union Electric Company d/b/a Ameren Missouri, and Ameren Transmission Company of Illinois (collectively, Ameren). In addition, on December 20, 2019, DTE Electric Company, Consumers Energy Company and Alliant Energy Corporate Services, Inc. (collectively, DTE), parties to both proceedings, filed a request for rehearing. On December 23, 2019, the Indicated PJM Transmission Owners (PJM TO)[62] filed a motion to lodge and request for rehearing.

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[61] For purposes of the their request for rehearing, CAPs include the following entities: American Municipal Power, Inc. (AMP); ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and Wisconsin Industrial Group (WIEC) (collectively, Joint Complainants); Joint Consumer Advocates, including Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Customers, including Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; Organization of MISO States, Inc. (OMS); Mississippi Public Service Commission (MS PSC), Missouri Public Service Commission (MO PSC) and Missouri Joint Municipal Electric Utility Commission (MJMEUC) (collectively, Missouri-Mississippi Parties or MOMs); and Southwest Electric Cooperative, Inc. (SWEC). For purposes of the CAPs briefs in the Second Complaint proceeding, CAPs include Industrial Consumer Groups (ICG), comprising ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and WIEC; Joint Consumer Advocates, comprising Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Complainants and Intervenor (JCI), comprising Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; OMS; Missouri-Mississippi Parties; and SWEC.

[62] For purposes of this filing, the PJM TOs are American Electric Power Service Corporation, on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company; Duquesne Light Company; Exelon; PPL Electric Utilities Corporation; and Public

24. In addition, multiple non-parties filed requests for rehearing and other motions. On December 23, 2019, the following entities filed such requests and/or motions: PPL Electric Utilities Corporation (PPL Electric) filed a motion to intervene out-of-time and motion to lodge; Southern California Edison Company (SoCal Edison) filed a motion to comment; American Electric Power Service Corporation[63] (AEP) filed a motion to intervene out-of-time and motion to lodge; San Diego Gas & Electric Company (SDG&E) filed a motion to intervene out-of-time and motion for Clarification, or in the alternative, request for rehearing; FirstEnergy Service Company (FirstEnergy) filed a request for rehearing and motion for late intervention; WIRES LLC filed a motion to intervene out-of-time, motion to lodge, and request for rehearing; Public Service Electric and Gas Company (PSEG) filed a motion to intervene out-of-time; Edison Electric Institute (EEI) filed a motion to intervene out-of-time, motion to lodge, and request for rehearing; AEP Indiana Michigan Transmission Company, Inc. filed a motion to intervene out-of-time; and the Southwest Power Pool, Inc. (SPP) Transmission Group[64] filed public comments concerning Opinion No. 569. On December 23, 2019, New England TOs[65] filed a letter requesting that, if the Commission intends to use the

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Service Electric and Gas Company. Some, but not all, of the PJM TOs have timely intervened in these proceedings.

[63] American Electric Power Service Corporation filed on behalf of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company.

[64] For purposes of this filing, the SPP Transmission Group is Evergy Kansas Central, Inc., Evergy Metro, Inc., Evergy Missouri West, Inc. (subsidiaries of Evergy, Inc. that were formerly known as Westar Energy, Inc., Kansas City Power & Light Company, and KCP&L Greater Missouri Operations Company, respectively), American Electric Power Service Corporation, on behalf of its affiliates, Public Service Company of Oklahoma, Southwestern Electric Power Company, Oklahoma Transmission Company and Southwestern Transmission Company (collectively AEP-West), The Empire District Electric Company (a Liberty Utilities company), Oklahoma Gas & Electric Company, and Southwestern Public Service Company.

[65] For purposes of this letter, the New England TOs are: Emera Maine f/k/a Bangor Hydro-Electric Company, Central Maine Power Company, New England Power Company d/b/a National Grid, New Hampshire Transmission LLC, Eversource Energy Service Company (on behalf of its operating company affiliates: The Connecticut Light and Power Company; NSTAR Electric Company; and Public Service Company of New Hampshire, each of which is doing business as Eversource Energy), The United

outcome of these proceedings to establish any ROE policies or precedent that would apply to the New England TOs, then the Commission consider the arguments that the New England TOs made in their supplemental brief in the complaint proceedings regarding their base ROE in which the *Coakley* Briefing Order was issued. On January 7, 2020, the American Public Power Association (APPA) and Transmission Access Policy Study Group (TAPS) filed a conditional motion to intervene out-of-time and conditional motion to lodge.

H. Subsequent Filings

25. On January 7, 2020, CAPs filed an answer in opposition to the late motions to intervene and alternative motion for leave to respond to non-party comments. On January 10, 2020, EEI and WIRES LLC filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 13, 2020, FirstEnergy filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 21, 2020, PPL Electric filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 28, 2020, CAPs filed a motion to strike portions of various entities' requests for rehearing and motions. On February 12, 2020, MISO TOs filed a motion for leave to answer and answer to certain portions of entities' requests for rehearing, as well as CAPs' January 7 answer and the APPA and TAPS January 7 conditional motion to intervene out-of-time and conditional motion to lodge. On February 12, 2020, the PJM TOs, MISO TOs and Exelon filed separate answers to CAPs' January 28 motion to strike. On February 13, 2020, Transource Energy also filed an answer to CAPs' January 28 motion to strike. On February 27, 2020, CAPs filed an answer to MISO TOs' February 12 answer.

II. Procedural Matters

26. We deny the motions to intervene out-of-time and the requests for rehearing and other motions included with those motions to intervene out-of-time. In ruling on a motion to intervene out-of-time, we apply the criteria set forth in Rule 214(d) of the Commission's Rules of Practice and Procedure.[66] When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for the granting of such late intervention.[67] In addition, it is generally Commission policy to deny late intervention at the rehearing

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Illuminating Company, Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, and Vermont Transco, LLC.

[66] 18 C.F.R. § 385.214(d) (2019).

[67] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,250, at P 7 (2003).

stage, including when the petitioner claims that the decision establishes a broad policy of general application.[68]

27. None of the entities that filed motions to intervene out-of-time have met their burden to justify granting late intervention, and we therefore deny their motions to intervene. We find that granting these late interventions at this stage of the proceedings would substantially disrupt the proceedings,[69] as well as prejudice and place significant additional burdens on the existing parties to these proceedings.[70] The entities seeking late intervention have not demonstrated good cause that would justify granting late intervention despite these negative consequences. This is particularly true in light of the fact that, as discussed below, parties will have an opportunity to argue that the base ROE methodology applied in any of these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that party.[71] Accordingly, we deny the motions to intervene out-of-time of PPL Electric, AEP, SDG&E, FirstEnergy, WIRES LLC, PSEG, EEI, AEP Indiana Michigan Transmission Company, Inc., and APPA and TAPS. As these entities are not parties to these proceedings, they may not seek rehearing of Opinion No. 569, and we reject their respective pleadings on that basis.[72]

28. SoCal Edison filed a motion to comment and the SPP Transmission Group filed what it styled as "public comments" regarding Opinion No. 569, without motions to intervene out-of-time. We find that these pleadings are effectively requests for rehearing and, because these entities are not parties to these proceedings, they may not seek rehearing of Opinion No. 569, and we reject their respective pleadings on that basis. We note that only some of the PJM TOs have timely intervened in these proceedings—Duquesne Light Company and Exelon—therefore we will address the requests for rehearing that those two parties made as part of the PJM TOs.

29. The motions to lodge filed by PPL Electric, AEP, WIRES LLC, EEI, and APPA and TAPS are essentially components of requests for rehearing of Opinion No. 569, and

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[68] *See, e.g., Seminole Elec. Coop., Inc.*, 153 FERC ¶ 61,037, at P 11 & n.14 (2015) (citing *PáTu Wind Farm LLC v. Portland General Elec. Co.*, 151 FERC ¶ 61,223, at P 39 & n.85 (2015) (citing *Columbia Gas Transmission Co.*, 113 FERC ¶ 61,066, at 61,243 (2005))).

[69] *See* 18 C.F.R. § 385.214(d)(1)(ii).

[70] 18 C.F.R. § 385.214(d)(1)(iv).

[71] *See infra* at P 204.

[72] 16 U.S.C. § 825*l* (2018); 18 C.F.R. § 385.713(b).

we therefore deny those motions because those entities are not parties to these proceedings. Moreover, even if we were to consider those motions to lodge, and the motion to lodge filed by PJM TOs, as not a component of a request for rehearing, we would deny those motions on the merits. Rule 716 provides that a proceeding may be reopened only when reopening is warranted by a change in condition of fact or law, or by public interest.[73] Additionally, a decision to reopen the record is a discretionary one for the Commission, and Commission policy discourages reopening records, except in extraordinary circumstances in order to prevent administrative chaos and provide finality to proceedings.[74] Further, a demonstration of extraordinary circumstances requires a showing of a material change that goes to the very heart of the case.[75] We find that the entities that filed motions to lodge have failed to show any compelling changes in law, fact, or public interest that would necessitate reopening of the record to lodge the materials that they seek to lodge. As discussed further below in section XV, to the extent that these entities are concerned that Commission actions in these proceedings will affect them and they have filed pleadings or materials in other proceedings that they want the Commission to consider before taking action with respect to their base ROEs, such entities will have an opportunity to present those pleadings or materials and argue that any Commission actions in these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that entity.

30. Given that we are denying the motions to intervene out-of-time, we find that CAPs' January 7 answer in opposition to the late motions to intervene or, in the alternative, motion for leave to respond to the pleadings, comments and requests for rehearing submitted by those entities, is moot and we reject it. We therefore also reject the answers to CAPs' January 7 answer submitted by EEI, WIRES LLC, FirstEnergy, PPL Electric, and MISO TOs. We also reject CAPs' January 28 motion to strike portions of various entities' requests for rehearing and motions. To the extent that this motion relates to contents of a motion to lodge that has been denied, as discussed above, we find that it is moot. To the extent that this motion relates to requests for rehearing, it is an answer to a request for rehearing and we reject it because it is prohibited by Rule 713(d)(1) of the Commission's Rules of Practice and Procedure.[76] We find that

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[73] 18 C.F.R. § 385.716(c).

[74] *See, e.g.*, *Gas Producing Enterprises, Inc.*, 28 FERC ¶ 61,008 (1984) (citing *Consolidated Gas Supply Corp.*, 24 FERC ¶ 61,283 (1983), *Transcontinental Gas Pipe Line Corp.*, 23 FERC ¶ 61,152 (1983), and *ICC v. Jersey City*, 322 U.S. 503 (1944)).

[75] *See, e.g.*, *CMS Midland, Inc., Midland Cogeneration Venture Limited Partnership*, 56 FERC ¶ 61,177, at 61,624 (1991).

[76] 18 C.F.R. § 385.713(d)(1).

CAPs have not shown good cause for us to waive this rule to allow their answer.[77] Because we are rejecting CAPs' January 28 motion to strike, we also reject the answers to that motion filed by PJM TOs, MISO TOs, Exelon, and Transource Energy. We reject MISO TOs' February 12 answer to requests for rehearing for the same reasons, and find that this answer is moot as it relates to the APPA and TAPS January 7 conditional motion to intervene out-of-time because, as discussed above, we are denying that motion to intervene out-of-time. Given that we are rejecting MISO TOs' February 12 answer, we also reject CAPs' February 27 answer to that answer.

III. General Model Issues

31. This section pertains to the Commission's decision in Opinion No. 569 to use two models in its base ROE analysis under section 206 of the FPA, rather than either using only the DCF model or using all four models proposed in the Briefing Order. It does not address the specific merits of the individual models, which are discussed in subsequent sections.

A. Opinion No. 569

32. The Commission found that averaging of multiple models reflected how investors made investment decisions and reduced model risk to the greatest extent possible. The Commission cited MISO TOs' witness, Mr. McKenzie, who explained that "when conditions associated with a model are outside of the normal range, there is a risk . . . that the theoretical model will fail to predict or represent the real phenomenon that is being modeled."[78] The Commission also cited Dr. Morin, who found that "Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."[79]

33. The Commission, for reasons specific to the Risk Premium and Expected Earnings Models, determined that they were not appropriate to use for determination of ROEs, for either the first or second prong of section 206 analyses. Opinion No. 569, applying the DCF model and CAPM, reduced the MISO TOs' ROE from the 10.32% prescribed in Opinion No. 551, which was itself a reduction from 12.38%, to 9.88%.

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[77] *See id.* § 385.101(e).

[78] Opinion No. 569, 169 FERC ¶ 61,129 at PP 38-39 (citing Docket No. EL14-12-001, Ex. MTO-22, at 18-19).

[79] *Id*. (citing Roger A. Morin, James, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) (Morin) at 428).

B. Requests for Rehearing

34. CAPs contend that the Commission erred by finding that the results of the DCF model alone were not just and reasonable. Specifically, CAPs contend that the Commission did not address the testimony of its expert, Dr. Keith Berry, arguing against the Commission's finding of model risk justifying the use of multiple models.[80]

35. Certain parties argue that the Commission acted arbitrarily and capriciously or otherwise did not engage in reasoned decision-making when it determined that the Risk Premium and Expected Earnings models should not be used for ROE determinations. Parties point out that the Commission endorsed using the Risk Premium and Expected Earnings Models in Opinion Nos. 531, 531-A, and 551, as well as the Briefing Order in these proceedings. Specifically, Exelon states that, in the Briefing Order, the Commission found that "it is clear that investors place greater weight on one or more of the other methods for estimating the expected returns from utility investments, as well as taking other factors into account."[81] Exelon contends that the Commission, in Opinion No. 569, insufficiently justified reversing course on this point. Exelon also argues that the Risk Premium and Expected Earnings Models should not be ignored due to their alleged deficiencies, asserting that the CAPM and DCF also have deficiencies. Ameren similarly contends that the Commission's reversal from the Briefing Order was unsupported and contradictory to its findings that investors rely on a diverse set of data sources.[82]

36. Transource Energy argues that the Commission, in Opinion No. 569, was internally inconsistent by giving no weight to the Expected Earnings and Risk Premium Models despite finding that investors rely on multiple models.[83] Transource Energy contends that four models provide a more complete picture than two models, which themselves share many common inputs. Transource Energy asserts that the Commission in Opinion No. 569 issued findings inconsistent with those in Opinion No. 531, which considered three other models, and notes that the Court did not find fault with this finding.[84] Transource Energy states that the CAPM results indicate that a 9.88% ROE was inadequate. Transource Energy also states that the midpoint of the CAPM was 10.45% and contends that no record evidence suggests that 10.45% is overstated.

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[80] CAPs Rehearing Request at 85-87.

[81] Exelon Rehearing Request (citing Briefing Order, 165 FERC ¶ 61,118 at P 37).

[82] Ameren Rehearing Request at 11-13.

[83] Transource Energy Rehearing Request at 15-16.

[84] *Id*. at 17-18

Transource Energy argues that the Commission has previously determined that the DCF is not reliable and that substantial evidence in the record demonstrates that the cost of capital is more consistent with the CAPM result than the DCF result for the complaint time period.[85]

37. Certain parties also argue that the reduction of MISO TOs' ROE in Opinion No. 569 is unjust and unreasonable on the basis that it reduces MISO TOs' ROE to an unreasonably low level. MISO TOs state that, in Opinion No. 551, "the Commission concluded that a 175-basis point ROE reduction . . . could put transmission investment at risk."[86] MISO TOs also argue that the ROE resulting from Opinion No. 569 could cause capital to be diverted to other purposes. Transource Energy similarly contends that the Commission has not supported a 9.88% ROE, and notes that it is below many of the benchmarks provided by state ROEs and other models.[87] Ameren also contends that this methodology threatens utility credit ratings and thus violates *Hope* and *Bluefield*. Specifically, they cite *Bluefield's* finding that the return "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[88]

38. Ameren and Transource Energy state that the Commission should not have excluded the Expected Earnings and Risk Premium models because they have flaws while keeping the DCF and CAPM models, which the Commission acknowledged also have flaws.[89] As an example of DCF and CAPM flaws, Transource Energy notes the Commission's finding in Opinion No. 551 that the DCF model is distorted by a low-interest rate capital market.[90] Ameren and Transource Energy argue, therefore, that the Commission's assertion that there exist imperfections in the Expected Earnings and Risk Premium models is not a valid justification for excluding those models.[91] According to Transource Energy, excluding the Expected Earnings and Risk Premium models results in twice the weighting for the DCF model, and Transource Energy notes

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[85] *Id.* at 14-15.

[86] MISO TOs Rehearing Request at 19 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 263).

[87] Transource Energy Rehearing Request at 11.

[88] *See, e.g., id*. at 6 (citing *Bluefield*, 262 U.S. at 693).

[89] Ameren Rehearing Request at 12; Transource Energy Rehearing Request at 23.

[90] Transource Energy Rehearing Request at 21-22.

[91] Ameren Rehearing Request at 12; Transource Energy Rehearing Request at 23.

that only including one other model with inputs which share similar characteristics to the DCF does not obviate the issue of whether the DCF is less reliable due to capital market conditions.[92]

39. Ameren and Transource Energy argue that the Commission should keep the four-model framework proposed in the Briefing Order because the Commission has stated that use of multiple models provides more accuracy, consistency with investor expectations, and robustness.[93] Ameren contends that the addition of the Expected Earnings and Risk Premium models would prevent an unreasonable restriction of the zone of reasonableness, and Transource Energy notes that the DCF and CAPM models provide the least diversification benefits of the four the Commission originally proposed.[94] Ameren argues that, when the Commission moved to a two-model ROE methodology, it failed to explain why it excluded certain models (i.e., the Expected Earnings and Risk Premium models) that are relied upon by investors. Ultimately, the new methodology gives zero weight to the excluded models when they were previously assigned a 25% weight in Opinion No. 569. Ameren asserts that the resulting ROE based on only the CAPM and DCF models is not supported by the record and is therefore arbitrary and capricious.[95] Ameren and Transource Energy state that the Commission's use of only the DCF and CAPM models fails to compensate MISO TOs for the actual risks associated with transmission infrastructure development.[96] Ameren and Transource Energy argue that this inadequacy amounts to failure of the capital attraction standards and threatens utility credit metrics, in violation of *Hope* and *Bluefield*.[97]

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[92] Transource Energy Rehearing Request at 21-22.

[93] Ameren Rehearing Request at 12-13; Transource Energy Rehearing Request at 15, 26.

[94] Ameren Rehearing Request at 12-13; Transource Energy Rehearing Request at 16-17, 19.

[95] SoCal Edison Comment, Docket No. EL14-12, at 11-12; Indicated PJM TOs Rehearing Request, Docket No. EL14-12, at 11; Ameren Rehearing Request, Docket No. EL14-12, at 23-25; Wires Comment Rehearing Request, Docket No. EL15-45, et al., at 17; Wires Comment Rehearing Request, Docket No. EL14-12, et al., at 7, 17; FirstEnergy Hearing Request, Docket No. EL15-45, at 3; Transource Energy Rehearing Request, Docket No. EL14-12, at 18-19.

[96] Ameren Rehearing Request at 6; Transource Energy Rehearing Request at 9-12.

[97] Ameren Rehearing Request at 6-7; Transource Energy Rehearing Request at 9-12.

40. MISO TOs also argue that the court's analysis in *Emera Maine* did not require the Commission to construct a new paradigm to satisfy the second prong of section 206. Instead, they argue, the Commission can remedy its error simply by evaluating "the alternative benchmarks and additional record evidence" that warrant selecting a base ROE greater than the midpoint (of whatever range of estimated returns on which the Commission elects to rely) to determine a new, just and reasonable base ROE.[98]

41. MISO TOs contend that, regardless of whether the base ROE prescribed by Opinion No. 569 is a midpoint value of some range of estimated ROEs, section 206 still requires the Commission to explain why, based on the evidence in the record, the new ROE is just and reasonable. MISO TOs contend that the Commission's new approach still fails to do so. MISO TOs contend that the mere fact that the newly prescribed ROE is the midpoint of the composite DCF-CAPM range of estimates does not make that value a just and reasonable ROE. According to MISO TOs, the Commission's selection of the average of the DCF and CAPM midpoints is no better justified in Opinion No. 569 than was the selection of the upper half midpoint found to be arbitrary and capricious in *Emera Maine*.[99]

42. With regard to the First Complaint, MISO TOs argue that *Emera Maine* does not require, and establishes no reason why, the Commission should fundamentally modify the approach of Opinion Nos. 531 and 551, other than to correct or avoid the specific errors the court pinpointed. They argue that the evidence more than amply supports the Commission's conclusion in Opinion No. 551 that the DCF midpoint of 9.29% (stated as 9.3% in Opinion No. 569) is too low to pass muster under *Hope* and *Bluefield*.[100]

C. Commission Determination

43. We disagree with CAPs' contention that the record does not support our finding of model risk as justifying no longer relying solely on the DCF model. Model risk includes the broad conceptual issue of models being imperfect and not always working well in all situations. It also entails errors of specific model inputs, such as the error discussed with respect to the Portland General Electric inputs, discussed in paragraph 145 below. We continue to find that ROE determinations should consider multiple models, both to capture the variety of models used by investors and to mitigate model risk. With respect to the former, we reiterate our findings from Opinion No. 569 in support of the finding

[98] MISO TOs Rehearing Request at 30-31.

[99] *Id.* at 31-32.

[100] *Id*. at 32.

that use of multiple models reduces model risk. Dr. Morin speaks of the type of potential model errors that comprise "model risk" and why use of additional models is warranted:

> In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulator should rely on the results of a variety of methods applied to a variety of comparable groups, and not on one particular method. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price.[101]

44. We also disagree with contentions that Opinion No. 569 resulted in rates that fail to meet the *Hope* and *Bluefield* standards for just and reasonable rates because they reduce the ROE. As an initial matter, the ROE resulting from this order will be materially higher than the 9.88% resulting from Opinion No. 569 for the First Complaint, rendering such concerns at least partially addressed. Second, cost-of-service principles dictate that the ROE should increase or decrease with the cost of capital. The Commission employs, and at times modifies, financial models, to determine this cost of capital. Although any rate reduction, by reducing earnings, will necessarily adversely affect certain financial metrics, that does not preclude the Commission from reducing rates. It is not incumbent on the Commission to demonstrate that any rate reduction, if supported by evidence demonstrating reduced cost of capital, would not adversely affect utilities' financial metrics. By the logic of certain parties, virtually any rate reduction would be unjust and unreasonable simply because it reduces the ROE and thus harms financial metrics for the affected utilities. In this case, the reduction in ROE from 10.32% in Opinion No. 551 to 9.88% in Opinion No. 569 was less than 4% and Opinion No. 569 extensively supported this such reduction.

45. As described below, we now find that the flaws for the Risk Premium model, when mitigated by certain adjustments, do not render use of the model unreasonable, while the flaws of the Expected Earnings model are significant enough to render the model inappropriate for ROE calculations. We are not persuaded by Ameren's and Transource Energy's arguments that the Expected Earnings model's flaws constitute an insufficient reason to exclude the model because the Commission has acknowledged that other models also have flaws. As the Commission explained in Opinion No. 569, the Commission considered the disadvantages and advantages of each model and concluded that, on balance, the disadvantages of the Expected Earnings model outweigh its

[101] Morin at 429.

advantages.[102] Simply because other models also have disadvantages does not mean that they have the same level of disadvantages or advantages as those of the Expected Earnings model. The Commission may use its discretion to determine which flaws in various models render the models unreasonable, and thus unusable, and which do not.

46. Regarding arguments that the Commission should include all four models because more models provide additional robustness, we agree—if the models are methodologically and legally sound. As described below, we conclude that the Risk Premium model, with adjustments, is sound, while the Expected Earnings model is not. We are not persuaded by arguments that all four models should be included because they broaden the zone of reasonableness. Such assertions, without support, suggest adopting a zone of reasonableness that is far wider than what the Commission has historically determined would be just and reasonable without sufficient justification as to why such a broader zone of reasonableness is appropriate. Nonetheless, our decision to now construct the ranges of presumptively just and reasonable ROEs by dividing the full zone of reasonableness into equal thirds instead of using the quartiles applied in Opinion No. 569, as discussed in section XIV below, at least in part addresses such concerns by widening the range of presumptively just and reasonable existing ROEs.

IV. DCF

A. Opinion No. 569

1. Short-Term Growth Rate

47. In Opinion No. 569, the Commission found that the DCF and CAPM models should employ IBES short-term growth rates.[103] In the context of the DCF, the Commission explained that IBES was preferable because the IBES growth projections generally represent consensus growth estimates by a number of analysts while *Value Line* growth estimates represent the growth projection of a single analyst.[104] The Commission explained that, while many investors use both IBES and *Value Line* growth rates, only IBES growth rates reflect the analysis of a diverse group of persons in the investment community.[105] The Commission cited academic research that supported the use of IBES

[102] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 209.

[103] *Id.* P 251.

[104] *Id.* P 125.

[105] *Id.*

because of its use of multiple analysts' growth projections instead of a single analyst.[106] In addition, the Commission noted that IBES growth projections are generally more timely than the *Value Line* projections because IBES updates its data base on a daily basis as participating analysts revise their forecasts, whereas *Value Line* publishes its projections on a rolling quarterly basis.[107]

2. Long-Term Growth Rate Weighting

48. In Opinion No. 531, the Commission adopted the same two-step DCF model for electric utilities as it has used for natural gas and oil pipelines since the mid-1990s. That model includes a projection of the long-term growth in dividends based on the growth in GDP, in addition to the short-term three to five-year growth projection. The long-term growth projection is given one-third weight, with a short-term growth projection given two-thirds weight.

49. In the Briefing Order, the Commission proposed no changes to its existing two-step DCF model. In Opinion No. 569, the Commission rejected the MISO TOs' contention that, if the Commission applied a high-end outlier test to the ROE results produced by the two-step DCF analysis, the Commission should eliminate the long-term growth projection.[108] Specifically, the Commission rejected MISO TOs' assertion that, if the Commission applies a high-end outlier test to the DCF model, there will remain no rationale for requiring the long-term growth component of the two-step DCF model.[109] The Commission found that the existence of the high-end outlier test is irrelevant to the question of whether a long-term growth projection should be included in a DCF analysis of public utilities.[110] The Commission stated that the high-end outlier test eliminates outlier proxy group members and that it does not address the fact that, over the long-term, companies cannot maintain their short-term growth rates and must, to some extent, converge on the growth rate of the overall economy.[111] Furthermore, the Commission stated that the high-end outlier test that it adopted in Opinion No. 569 does not screen out any of the ROEs produced by the DCF analysis of the proxy groups in these two cases,

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[106] *Id.*

[107] *Id.* P 128.

[108] *Id.* PP 151-159.

[109] *Id.* P 159

[110] *Id.*

[111] *Id.*

including the ROE results discussed above that establish the top of the zones of reasonableness in these two cases.[112]

B. Rehearing Requests

1. Short-Term Growth Rate

50. RPGI states that the Commission correctly used IBES consensus earnings growth estimates rather than *Value Line* earning growth estimates.[113]

51. MISO TOs state that the Commission erred in finding that "IBES is more reliable and robust" than *Value Line* and choosing to use the IBES three to five-year growth projection over *Value Line* growth projections.[114] MISO TOs assert that the Commission erred in finding that there was a general consensus by citing a witness's belief that IBES growth estimates have a higher potential for representing a broader investor community, and the Commission cannot accurately characterize IBES estimates as consensus estimates.[115]

52. MISO TOs assert that the Commission wrongly attempted to relegate *Value Line*'s estimates as "projections by a single institution."[116] MISO TOs argue that the Commission's statement minimizes the fact that *Value Line* estimates are consensus estimates that are the results of a committee composed of peer analysts, and not simply the product of a single analyst.[117] MISO TOs also state that merely averaging analysts' estimates does not create a consensus, and there is no indication that the analysts behind the IBES estimates agree on the published value.[118]

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[112] *Id.*

[113] RPGI Rehearing Request at 61.

[114] MISO TOs Rehearing Request at 63 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 133).

[115] *Id.* at 64 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 127 (quoting Commission Trial Staff witness Mr. Robert J. Keyton)).

[116] *Id.* (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 125 n.278).

[117] *Id.* at 64-65.

[118] *Id.* at 65.

53. MISO TOs assert that the Commission's stated preference for IBES over *Value Line* because it is more current is not supported by the record and is arbitrary and capricious.[119] MISO TOs state that the Commission appears to rely on the misperception that IBES' estimates are more up-to-date than *Value Line* simply because IBES can update its daily estimates on a daily basis.[120]

2. Long-Term Growth Rate Weighting

54. MISO TOs request rehearing of the Commission's decision not to adopt any changes to its existing two-step DCF model, averring that, if the Commission adopts a high-end outlier test, it should remove the long-term growth rate portion of the two-step DCF analysis.[121] MISO TOs contend that although no single approach provides a "one-size-fits-all" scenario for estimating the cost of capital, a constant growth DCF better represents investor expectations for the MISO TOs than a two-step DCF model using a long-term growth rate component.[122]

C. Commission Determinate

1. Short-Term Growth Rate

55. We will maintain the longstanding practice of using IBES short-term growth rates for the DCF model, absent compelling reasons for using an alternative source.[123] The record in this and numerous prior proceedings illustrates that the IBES growth rates appropriately inform the DCF analysis.[124] We continue to find that IBES is a reliable source of short-term growth rate data for the DCF model[125] and find that it is appropriate to continue to rely on IBES short-term growth rates in the DCF model given the

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[119] *Id.* at 66.

[120] *Id.* at 66-67.

[121] *Id.* at 77.

[122] *Id.* at 80 (citing McKenzie Supplemental Initial Brief Affidavit, Docket No. EL14-12, at 51–52).

[123] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at P 133 ("absent compelling reasons why, we will continue to rely exclusively on IBES as the preferred source for short-term growth projections for the purpose of performing the DCF analysis.").

[124] *See, e.g.*, *id.* at PP 120-133.

[125] *See id.* PP 125-128.

Commission's longstanding practice of relying on those IBES short-term growth rates in the DCF model[126] and the experience that entities coming before the Commission have gained in using IBES in the DCF model in light of that practice. However, we find that, although IBES short-term growth rates should be used for the DCF model,[127] the Commission will consider use of *Value Line* in future proceedings for the CAPM methodology, as discussed below.

2. Long-Term Growth Rate Weighting

56. We disagree with the MISO TOs' request that, if the Commission adopts a high-end outlier test, it should remove the long-term growth rate portion of the two-step DCF analysis and that a constant growth DCF better represents investor expectations for a two-step DCF model using a long-term growth rate component. However, as we note below, we are modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. Although we are not adopting MISO TOs' proposed change, upon reconsideration, we agree that changes to the long-term growth rate are warranted.

57. We grant rehearing to give the short-term growth rate 80% weighting and the long-term growth rate 20% weighting. We note that the court in *CAPP v. FERC*[128] held that the Commission has broad discretion in its weighting choice. Since the Commission established its one-third weighting policy of the GDP in the long-term growth rate, short-term growth rate projections for electric utilities have declined and are now closer to the current GDP growth projection than those from the 1990s when the Commission adopted the two-step DCF using one-third weighting for GDP in the long-term growth

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[126] *See id.* PP 121-123.

[127] In addition, with respect to the First Complaint proceeding, IBES short-term growth rates are the only data available in the record for the study period. *See, e.g.*, MISO TOs Initial Br. (I) at 22 ("MISO Transmission Owners do not propose reliance on growth rates from a source other than IBES to resolve the First Complaint."); MISO TOs Rehearing Request, Docket No. EL14-12-000, at 3 ("The MISO Transmission Owners . . . did not take exception to the Presiding Judge's adoption of the June 2015 Update Period as the appropriate study period for this case. Since they did not object to the June 2015 Update Period, and since there was no *Value Line* growth rate evidence related to that period, the MISO Transmission Owners had no quarrel with, and did not take exception to, the ALJ's ruling that his adoption of the June 2015 Study Period "dictate[d] use of IBES growth rates" insofar as Docket No. EL14-12 was concerned.").

[128] 254 F.3d 289 (D.C. Cir. 2001).

rate for natural gas and oil pipelines[129] that was subsequently adopted for public utilities.[130] For example, in Opinion No. 531, which considered market conditions during the time period from October 2012 to March 2013, the IBES growth projections of the proxy group (before the exclusion of low-end outliers) ranged from -1.90% to 8.10% and averaged 4.58%, only 19 basis points above the 4.39% GDP growth projection in that proceeding.[131] In the First Complaint proceeding, which considered market conditions during the time period from January 2015 to June 2015, the IBES growth projections of the proxy group (before the exclusion of low-end outliers) ranged from -0.64% to 11.66% and averaged 5.03%, 64 basis points above the projected growth in GDP in that proceeding of 4.39%.[132] By contrast, when MISO's 12.38% base ROE was established in 2002, the average IBES short-term growth rate estimate for that year was 7.79%,[133] a full 158 basis points above the estimated 6.21% GDP growth rate from a contemporaneous natural gas pipeline filing.[134]

58. Additionally, average electric utility IBES growth projections are only marginally higher than GDP growth projections. Under these circumstances, investors are likely to view electric utility IBES growth projections as more sustainable than the substantially higher natural gas pipeline IBES growth projections when the Commission established its two-thirds/one-third weighting policy. Therefore, it is reasonable to give the IBES growth projection more weight and give the GDP growth projection less weight. This finding is consistent with Opinion No. 414-A's findings that "long-term projections are

[129] For example, *New York State Electric & Gas Corp.*, 85 FERC ¶ 63,002 (1998). In Footnote 22, the Initial Order references a GDP growth rate of 5.08%, which was an average of three estimates: 5.10% from Data Resources Inc., 4.95% from Wharton Econometric Forecasting Associates, Inc., and 5.20% from the Energy Information Administration.

[130] *See* Opinion No. 531, 147 FERC ¶ 61,234 at PP 17-23, 32.

[131] *See id.* P 38 and Appendix.

[132] Opinion No. 569, 169 FERC ¶ 61,129 at P 135; Appendix A.

[133] *See Midwest Indep. Transmission Sys. Operator, Inc.,* 100 FERC ¶ 61,292 at app. A.

[134] *See* Trailblazer Pipeline Company, Testimony of Peter J. Williamson, Docket No. RP03-162-000, at P 19.

inherently more difficult to make, and thus are less reliable than short-term projections."[135]

59. We still believe that it is appropriate to consider the long-term growth rate to some extent, but now find that it is appropriate to afford less influence to the long-term growth rate. As the Commission held in Opinion No. 531:

> The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate commensurate with the investment's risk.[136] Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that 'projections by investment advisory services of growth for relatively short periods of years into the future' cannot be relied on 'without further consideration.' Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.[137]

60. As the Commission found in Opinion No. 531, we continue to recognize the need for a long-term growth projection to "aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy."[138]

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[135] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,423 (1998).

[136] As the Commission explained, "The DCF model assumes growth for an infinite period of time. This can be approximated as 50 years because the present value of a one dollar dividend received 50 years in the future, discounted at 12%, is less than one cent." *Ozark Gas Transmission Sys*., 68 FERC at 61,105 n.32 (citing Eugene F. Brigham & Louis C. Gapenski, Financial Management 291 (1991)).

[137] Opinion No. 531, 147 FERC ¶ 61,234 at P 33 (quoting *Consol. Gas Supply Corp.*, 24 FERC ¶ 61,046, at 61,105 (1983)) (footnotes omitted).

[138] *Id.* P 38 (quoting Opinion No. 414-A, 84 FERC at 61,423-24).

V. CAPM

A. Opinion No. 569

1. Use of Betas and Size Adjustments

61. In Opinion No. 569, the Commission noted that the Commission found in Opinion No. 531-B that the size adjustment was "a generally accepted approach to CAPM analyses" and continued to find this to be the case.[139] The Commission stated that there was substantial evidence in the record that investors rely on *Value Line* betas. While the Commission acknowledged that there is an imperfect correspondence between the size premia being developed with different betas, it concluded that the size adjustments improve the accuracy of the CAPM results and cause it to better correspond to the costs of capital estimates employed by investors.[140]

62. The Commission also found that the application of size adjustments based on the New York Stock Exchange (NYSE) to dividend-paying members of the S&P 500 is acceptable, as the use of the NYSE for the size premium adjustment enabled Ibbotson Associates to develop a rich data set,[141] and found no evidence that companies in the S&P 500 feature different risk premiums than those in the NYSE.[142]

63. The Commission disagreed with intervenors that the utility industry is unique, and that the size premium adjustment would therefore be inapplicable, as the size premium adjustments are supported by a robust data set. The Commission noted that there are variations in the risk profiles of firms of any industry and there was insufficient evidence in the record to conclude that factors specific to the utility industry insulate smaller utilities from risks such that the CAPM betas sufficiently account for any increased risks and corresponding returns demanded by investors.[143]

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[139] Opinion No. 569, 169 FERC ¶ 61,129 at P 296 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117).

[140] *Id.* P 297.

[141] Ibbotson Associates, now under Duff & Phelps, has long published a series quantifying this effect for various sizes of firms, pulling from data going back to 1926.

[142] *Id.* P 298.

[143] *Id.* P 303.

2. Exclusion of Growth Rates

64. In Opinion No. 569, the Commission accepted Trial Staff's proposal to screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20%. The Commission stated that such a screen is consistent with the elimination of outliers elsewhere in the ROE methodology, as such high or low growth rates are highly unsustainable and non-representative of the growth rates of the electric utilities in the proxy groups.[144]

B. Rehearing Requests

1. Use of Betas and Size Adjustments

65. CAPs state that the size adjustment is inconsistent with other elements of the adopted CAPM model. CAPs explain that the CAPM analysis incorporating a *Value Line* adjusted beta designed to measure market capitalization and a size premium adjustment based on raw betas is not based on substantial evidence.[145] Additionally, CAPs assert that the academic articles cited in Opinion No. 569 do not support the notion that investors rely on size factors.[146]

66. CAPs also argue that Opinion No. 569 appears to have misunderstood CAPs' concerns about the impact of mismatched betas as being whether the *Value Line* adjusted betas are appropriate for use in the CAPM. RPGI states that the issue before the Commission, however, was whether it is appropriate to combine adjusted and raw betas when performing a base CAPM analysis and applying a size premium adjustment.[147]

67. LPSC contends that the size adjustment is flawed because including such an adjustment conflicts with the Commission's determinations that utility growth rates will, in the long run, grow at the rate of the average firm in the economy.[148] LPSC also states that the Commission failed to address its contention that *Value Line* betas are methodologically mismatched to the S&P 500 because *Value Line* betas are calculated

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[144] *Id.* P 267.

[145] CAPs Rehearing Request at 77.

[146] *Id.* at 80.

[147] RPGI Rehearing Request at 77.

[148] LPSC Rehearing Request at 10.

using the NYSE, a different stock index.[149] LPSC asserts that the Commission incorrectly relies on raw betas in its size adjustment portion of the CAPM, while relying on adjusted betas in the rest of its CAPM analysis.[150]

68. RPGI states that the Commission erred by authorizing a size adjustment to the CAPM methodology that is unsupported by substantial record evidence and which arbitrarily inflated the ROE to an unjust and unreasonable level.[151] RPGI asserts that MISO TOs' comments did not recognize that the size premium adjustment is narrowly tailored to address an inability of beta to fully account for the impact of firm size within the CAPM, but failed to recognize that the size adjustment is of firms across the entire economy.[152] RPGI contends that Mr. Parcell's analysis shows that the size adjustment is inappropriate for regulated monopoly electric utilities. They aver that the Commission's silence on the simplification of Mr. Parcell's analysis is a central issue, and that the evidence contradicts the Commission's analysis.[153]

2. Exclusion of Growth Rates

69. MISO TOs argue that the Commission erred in excluding growth rates that are negative or in excess of 20% and argue that this adjustment has no economic justification.[154]

70. Exelon asserts that the Commission discards without justification companies with an IBES growth rate of greater than 20% from the CAPM.[155]

71. CAPs contend that the equity market return estimate, if calculated based on the short-term growth rate, should not exclude S&P 500 companies with negative growth rates. They aver that such exclusions are inappropriate because companies can feature negative growth rates for an extended period. Further, CAPs argue that, for the analysis

[149] *Id.* at 11.

[150] *Id.* at 14-15.

[151] RPGI Rehearing Request at 31.

[152] *Id.* at 32.

[153] *Id.* at 32-33.

[154] MISO TOs Rehearing Request at 69.

[155] Exelon Rehearing Request at 13.

to be appropriately diverse, these companies should be included, noting that such exclusions include some companies in the electric proxy group.[156]

3. Other Issues

72. Transource Energy asserts that the anomalous capital market conditions that called the DCF midpoint into question also suggest that the CAPM result would be too low, as the CAPM is premised in part on long-term Treasury bond yields.[157]

73. CAPs state that Opinion No. 569's specification of the CAPM methodology is erroneous and produces excessive results.[158] CAPs also note that independent estimates of the CAPM equity market return by financial institutions and other regulators are much lower than the Commission's estimates in Opinion No. 569.[159]

74. LPSC argues that the use of a one-step market DCF analysis in the CAPM fails to account for the long-term growth of stocks in the S&P 500, despite that utility stocks are long-term investments.[160] LPSC argues that the dividend-paying firms in the S&P 500 are not representative of the required return of the market as a whole, and solely relying on those firms results in the required market return being overstated. LPSC further argues that the exclusion of long-term GDP growth rates suggests that these high short-term growth rates will continue in perpetuity, which cannot be true.[161] LPSC further argues that the inclusion of mature, large market cap companies is not a remedy, as even these companies have an average growth rate significantly higher than long-term GDP growth.[162]

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[156] CAPs Rehearing Request at 65-68.

[157] Transource Energy Rehearing Request at 14-15.

[158] CAPs Rehearing Request at 59.

[159] *Id.* at 61-65.

[160] LPSC Rehearing Request at 6.

[161] *Id.* at 7-8 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 264).

[162] *Id.* at 8 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 265).

C. Commission Determination

1. Use of Betas and Size Adjustments

75. We continue to find reasonable the use of *Value Line* adjusted betas in the CAPM methodology, as well as the use of raw betas based on the NYSE in the size premium adjustment. We also continue to find that the size adjustment is necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity. As we found in Opinion No. 569, there is substantial evidence indicating that investors rely on *Value Line* betas in making investment decisions.[163] Furthermore, we are not persuaded by LPSC's argument that betas calculated based on the NYSE cannot be used with the S&P 500. We continue to find that size adjustments are appropriate for the utility industry and improve the overall accuracy of the CAPM results.[164]

76. We agree with LPSC that there is imperfect correspondence with applying *Value Line* betas derived from the NYSE to risk premiums developed using the S&P 500. However, we find that it is not reasonable to calculate the risk premium using the full 2800 companies in the NYSE. Furthermore, no parties assert that investors do not use *Value Line* betas or that such betas are materially different from betas derived from only the S&P 500. Thus, while not a perfect match, we find that the use of *Value Line* betas is appropriate for the CAPM calculation.

2. Exclusion of Growth Rates

77. We are not persuaded by MISO TOs' arguments that the CAPM methodology should consider growth rates that are negative or above 20% and continue to find that such a screen is consistent with the elimination of outliers elsewhere in the ROE methodology. Similarly, we disagree with CAPs that negative growth rates should be included. Negative and very high growth rates are both unsustainable and should thus be excluded from the determination of the CAPM risk premium, even if they enhance the diversity of covered companies.[165]

3. Source of Short-Term Growth Rates

78. For the reasons discussed above, we find that IBES is a reliable source of short-term growth rate data and therefore we find it reasonable for IBES growth rates to

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[163] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 297.

[164] *See id.* PP 297-298, 301, 303.

[165] *See id.* PP 267-268.

be used in the CAPM model. However, we clarify here that we will consider the use of *Value Line* short-term growth rates for the CAPM model in future proceedings. Consistent with our finding that it is beneficial to use different models in the ROE methodology, we find that it may be beneficial to diversify the data sources as well. We believe that diversifying data sources may better reflect the data sources that investors consider in making investment decisions and mitigate the effect of any unusual or incorrect data in a given source. Furthermore, as MISO TOs assert, there is substantial evidence that *Value Line* is used by numerous investors.[166] The Commission has, since Opinion No. 531, recognized the merit of *Value Line* data, as illustrated by its support for *Value Line* betas, discussed above.

79. We are purposefully taking different approaches for the sources of short-term growth rate data in the DCF and CAPM. We believe that, in keeping with the Commission's historic use of IBES for the DCF, the DCF should continue to use IBES short-term growth rate data, as discussed above. By contrast, we believe that the CAPM is a better candidate for a new growth rate data source given that the Commission is newly adopting the CAPM as a direct input into its determination of the zone of reasonableness under the first prong of section 206 and its selection of a just and reasonable replacement ROE under the second prong of section 206.

80. While the Commission found in Opinion No. 569 that IBES data is preferable because it represents consensus growth estimates by a number of analysts, upon further consideration, we conclude that, while *Value Line* estimates may come from a single analyst, those estimates are vetted through internal processes, including review by a committee composed of peer analysts, and thus they similarly incorporate the input of multiple analysts.

81. The Commission also found in Opinion No. 569 that IBES data is preferable because IBES projections are updated more often than the *Value Line* projections. However, after further consideration of the record, including broad requests to allow the use *Value Line* projections,[167] we find here that there is also value in including *Value Line* projections because they are updated on a more predictable basis. *Value Line*'s regular updates provide certainty about updates to key model inputs.

82. Therefore, we conclude that IBES and *Value Line* data both have advantages and thus it is appropriate to consider both data sources. As stated above, however, we believe

[166] *See, e.g.*, MISO TOs Rehearing Request at 63-69.

[167] *See, e.g.*, *id.* at 63-67; MISO TOs Initial Br. (I) at 22-23; MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 19-20.

it is appropriate to only consider using *Value Line* in the CAPM, which is being newly adopted, while continuing the traditional exclusive use of IBES data in the DCF model.

83. Although we find it appropriate to consider the use of *Value Line* short-term growth rates in the CAPM in future proceedings, we find that the record in these proceedings is insufficient to adopt use of *Value Line* growth rates for the CAPM at this time. Rather, we will evaluate proposals to use *Value Line* short term growth rates in the CAPM based on evidence produced in future proceedings. As we determine here, consistent with Opinion No. 569,[168] the Commission will screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20%. The only CAPM analyses in the record here that apply this screen are those provided by Trial Staff, which use only IBES short-term growth rates.[169] Thus, there is no CAPM analysis in the record that applies the growth rate screen to *Value Line* short-term growth rates. Moreover, we note that, even if we could determine a way in which to apply this screen to the data available in the record, no party has provided a CAPM analysis using only *Value Line* short-term growth rates or another analysis that would allow us to reliably derive a CAPM analysis using only *Value Line* short-term growth rates. The CAPM analyses provided by MISO TOs in these proceedings, which average IBES and *Value Line* short-term growth rates, do not contain sufficient information to allow us to reliably produce a CAPM analysis using only *Value Line* short-term growth rates because those analyses do not specify the weighted average earnings growth rates from *Value Line* that were used in arriving at the short-term growth rates which average IBES and *Value Line*.[170] Accordingly, although we believe, as discussed above, that it may be appropriate to use *Value Line* short-term growth rates in the CAPM, we find that we do not have sufficient record evidence to support adopting such use in these proceedings. Therefore, we will continue to use the CAPM analyses provided by Trial Staff here, but we will consider *Value Line* data in future proceedings.[171]

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[168] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 19, 267-268.

[169] *See id.* PP 513 n.1002, 555 n.1048.

[170] *See also* CAPs Rehearing Request, Docket No. EL14-12-002 at 55-56 n.193 ("The record on this issue . . . does not break out the Ex. MTO-30 growth inputs either by source or by S&P 500 company.").

[171] These analyses are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See also* Trial Staff Initial Br. (I), Attachment A to App. 2 at 6; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

4. Other Issues

84. We disagree with Transource Energy's and CAPs' assertions that the Commission's CAPM methodology produces inadequate and excessive results, respectively, and continue to find the Commission's CAPM methodology to be consistent with conventional CAPM methodologies. Regarding assertions that the CAPM results here exceed those used in other contexts, the Commission is not obligated to use the same exact ROE calculations as other regulatory bodies or investment services, and our CAPM calculations are specific to the electric utility industry. Regarding assertions that the results are unreasonably low, as discussed above, the mere decline of the ROE does not demonstrate that results are unreasonable, and, as discussed below, state-jurisdictional retail ROEs do not serve as an explicit floor on Commission-jurisdictional transmission ROEs.

85. We also continue to find that the CAPM should use a one-step DCF for its risk premium. This is because the rationale for using a two-step DCF methodology for a specific group of utilities does not apply when conducting a DCF study of the dividend-paying companies in the S&P 500, as the Commission found in Opinion Nos. 531-B and 569.[172] A long-term component is unnecessary because of the regular updates to the S&P 500, which allows it to continue to grow at a short-term growth rate and because S&P 500 companies include stocks that are both new and mature, the latter of which have a moderating effect on the short-term growth rates.[173]

86. We also find unsupported Transource Energy's assertion that the anomalous capital market conditions the Commission found rendered the DCF results too low also render the CAPM too low. We are no longer relying on such arguments based on the court's remand of Opinion No. 531. Furthermore, Transource Energy offers no evidence that the CAPM results in this proceeding were unreasonably low.

VI. Risk Premium

A. Opinion No. 569

87. In Opinion No. 569, the Commission determined that it would not use the Risk Premium model for either the first or second prong of the ROE analysis under section 206 of the FPA. It concluded that the Risk Premium model's deficiencies outweigh the additional robustness that it provides. Furthermore, the Commission found that the Risk Premium model requires methodological decisions that would likely

[172] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113; Opinion No. 569, 169 FERC ¶ 61,129 at P 263.

[173] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 264-266.

undermine transparency and predictability in Commission outcomes.[174] The Commission also explained that the Risk Premium model is largely redundant with the CAPM in that both models use indirect measures to ascertain the risk premium.[175]

88. The Commission agreed with CAPs that the Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations. It found that those determinations' ROE results may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. The Commission noted that many previous ROE determinations used in the Risk Premium model were from rate case settlements and that such settlements often involve compromises on a variety of non-ROE issues.[176]

89. The Commission also determined that circularity is particularly direct and acute with the Risk Premium model because it relies on past Commission ROE decisions. The Commission found that MISO TOs' regression analysis accentuates such circularity by largely offsetting the effects of changes in interest rates.[177]

90. The Commission also expressed doubt concerning the application of the regression analyses used by MISO TOs in their Risk Premium model. The Commission contrasted the impact of MISO TOs' analysis, which indicated an increase in the risk premium of 75 basis points for every 100 basis point decline in interest rates, with Dr. Morin's analysis, which indicated an adjustment of 48 basis points. The Commission found that, unlike for DCF and CAPM calculations, MISO TOs did not update and add to the data set for ROE proceedings through the end of the test period in June of 2015, further reducing the robustness of the data set. The Commission observed that, due to using the average of ROEs from each year, MISO TOs' regression in the First Complaint proceeding only has nine observations in its regression, which is a low number of observations for a linear regression and could impact the reliability of the results. The Commission found that MISO TOs' regression created a dynamic in which the Risk Premium analysis will keep the ROE essentially stable in contravention of general financial logic that lower interest rates make it easier to raise capital based on both the reduced opportunity cost of investing in bonds and greater availability of revenue to

[174] *Id.* P 340.

[175] *Id*. P 341.

[176] *Id*. P 342.

[177] *Id.* P 343.

invest due to the opportunity for carry trades where borrowing low-cost debt is used to finance equity purchases.[178]

91. Additionally, the Commission found that there was insufficient record evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions.[179] The Commission was also unpersuaded by MISO TOs' arguments that the nature of the industry and the resulting risk premiums changed following the Energy Policy Act of 2005 sufficiently to ignore prior data.

92. The Commission also reconsidered its finding in Opinion No. 531-B that "[g]iven the varying duration of regulatory proceedings, it is difficult, if not impossible, to ensure precise contemporaneity between long-term Treasury bond yields and the cost of equity allowed by a regulator."[180] The Commission found that, although an analysis with such imprecision may have been sufficient for using the Risk Premium model for corroborative purposes, direct use of the model to determine the risk premium would require actual alignment of the test periods and the dates assigned for purposes of comparing the ROE to the risk free rate of return. The Commission stated that, if it were to adopt a precise timing in this proceeding, as a practical matter, such a decision would likely require the Commission to exclude certain proceedings whose test periods predate 2006 and include others, as well as potentially change the dates assigned to yet other proceedings.[181]

93. The Commission also noted that the Risk Premium model entails numerous judgment calls which could be disputed by parties, such as: determining the risk premium resulting from proceedings resolved by settlements with different ROEs for different parties or time periods; whether the ROEs should be assigned to different times for purposes of the Risk Premium analysis; and whether ROEs from settlements resolving multiple proceedings with the same ROE should be counted once or twice. The Commission also noted other methodological decisions, including whether to look at the annual average of ROEs and corresponding risk-free rates of return or look at them individually. Because of this, the Commission found that the Risk Premium model

[178] *Id*. P 344.

[179] *Id*. P 345.

[180] *Id*. P 348 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98).

[181] *Id.*

features far more ambiguity and potential for dispute than the DCF and CAPM models, which would lead to higher costs for participation and less predictable results.[182]

94. The Commission stated that the output that the Risk Premium model produces is a single numerical point, and therefore, it does not produce a range which can be used to determine a zone of reasonableness. Accordingly, the Commission explained, the Briefing Order proposed to only use the Risk Premium model in the second prong of the section 206 analysis, but not in the first prong. The Commission stated that it preferred to use the same models in the prong one and prong two analyses to ensure that our ROE determinations under each prong are based on the same data and models and that there was no compelling justification to use different models and data sources to apply this same standard under the two prongs.

B. Rehearing Requests

95. Transource Energy argues that the Commission should utilize the Risk Premium model. Transource Energy argues that none of the Commission's justifications for using the DCF model and CAPM but not the Risk Premium model support reversing its prior findings that the imperfections of the Expected Earnings analysis and Risk Premium models do "not undermine" their usefulness.[183] Transource Energy contends that the Risk Premium model adds useful information that does not rely on the same assumptions as the DCF and CAPM models.[184]

96. Transource Energy also avers that the Commission has not shown that investors do not rely on the Risk Premium (or Expected Earnings) model and that, at most, the Commission shows that investors use those approaches differently than the DCF and

[182] *Id.* PP 346-350.

[183] Transource Energy Rehearing Request at 23 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98).

[184] *Id*. (citing Avera Test., Ex. MTO-1, Docket No. EL14-12, at 94 (explaining that unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields)).

CAPM models.[185] Transource Energy further points to the publication of returns granted by regulators as evidence that investors rely on the Risk Premium model.[186]

97. MISO TOs contend that the implementation questions raised in Opinion No. 569 do not undermine the probity of the Risk Premium analysis supplied by MISO TOs. MISO TOs contend that the Commission's decision in Opinion No. 569 to disregard this evidence is inconsistent with Opinion No. 551, where the Commission evaluated those issues and found that the model was probative.[187]

98. MISO TOs disagree with the Commission's finding that the Risk Premium model is redundant with the CAPM. MISO TOs note that the Risk Premium model focuses on the bond market while the CAPM focuses on the equity market, using different inputs. MISO TOs contend that investors independently rely on both models and note that many jurisdictions employ a Risk Premium approach for determining utilities' cost of equity.[188] MISO TOs argue that the Commission's finding that the stability of the Risk Premium model "defies general financial logic" overlooks that the data inputs used in the Risk Premium model inherently smooth out volatility.[189] They also argue that the Commission's assertion that the DCF and CAPM approaches may have a greater prevalence does not go to the merits of the Risk Premium approach, and it contradicts the record and the Commission's prior finding that Risk Premium is a traditional method investors may use to estimate the expected return from an investment in a company.[190]

99. MISO TOs argue that implementation issues associated with the Risk Premium method are neither insurmountable nor unique to the Risk Premium method. They argue that the Commission's concerns about which ROE inputs to include and "how far back such data should go" are directly analogous to questions regarding proxy group selection and the determination of the study period for the DCF analysis.[191]

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[185] *Id*. at 24.

[186] *Id*. at 25, n.13 (citing MISO TOs, Supplemental Reply Brief, Docket No. EL14-12-003, App. 2 at 44).

[187] MISO TOs Rehearing Request at 52-53.

[188] *Id*. at 47-49.

[189] *Id*. at 48.

[190] *Id.* at 49 (citing Briefing Order, 165 FERC ¶ 61,118 at P 36).

[191] *Id.* at 50.

100. MISO TOs assert that the Commission's concerns regarding circularity arising from using Commission-approved ROEs as inputs are overblown and present in other methodologies. MISO TOs contend that such circularity is limited because of the presumption that orders and settlements are based on market-based methodologies.[192] MISO TOs also aver that the lack of a resulting zone of reasonableness from the Risk Premium model is not a problem because the evaluation of whether an ROE remains just and reasonable is less exact than setting a new base ROE. MISO TOs contend that, while the Commission should include the Risk Premium in setting new ROEs, it does not necessarily need to include it in evaluating existing ROEs.[193]

101. MISO TOs also contend that the Commission's failure to provide guidance on the Risk Premium model's implementation is not a valid justification for omitting the model, particularly since the Commission has reopened the implementation of the models in this proceeding.[194]

102. PJM TOs contend that investors recognize that each of the four financial models in the Briefing Order has its own advantages and disadvantages. PJM TOs contend that investors use multiple models because no single model provides accurate results under all market conditions.[195]

103. PJM TOs argue that the Risk Premium model complements the Commission's DCF model by recognizing that the Risk Premium varies over time and with interest rates whereas the DCF model does not account for this variation.[196] PJM TOs argue that the Commission-authorized ROEs used in the Risk Premium model reflect inputs and analyses of multiple experts as well as the Commission's judgment concerning factors that affect the cost of equity, and contend that investors are likely to consider Commission-authorized ROEs to an extent.[197]

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[192] *Id*. at 50-51.

[193] *Id*. at 51-52.

[194] *Id*. at 49-50.

[195] PJM TOs Rehearing Request at 12.

[196] *Id.* at 26.

[197] *Id*. at 15-16.

C. Commission Determination

104. Upon reconsideration and with the modifications described below, we find that the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models.

105. In Opinion No. 569, the Commission expressed concerns that the Risk Premium model was an iteration of the CAPM, where both compared a derived return to a risk-free rate of return, affording too much weight to similar models. Upon reconsideration, we agree with the PJM TOs that the Risk Premium model is sufficiently distinct from the CAPM to use in our ROE analysis. The Risk Premium relies on corporate utility bonds while the CAPM uses Treasury Bond yields. Additionally, the Risk Premium model relies on the risk premiums implicit in regulatory judgements, including those using the DCF model, while the CAPM relies upon a different set of inputs, including S&P 500 dividend yields and growth rates as well as adjusted betas.

106. The Commission, in Opinion No. 569, found that the Risk Premium model contained substantial circularity. Upon reconsideration, we agree with MISO TOs[198] and find that, while it contains some circularity, the averaging of the results with those of the DCF and CAPM models sufficiently mitigates that circularity. Additionally, all of the models contain some circularity. And, upon consideration of the rehearing requests, we believe that the level of circularity in the Risk Premium model is acceptable.

107. The Commission also found that use of the Risk Premium model was inconsistent with the other models because it could only be used for the second prong of the section 206 analysis because it does not produce a zone of reasonableness. We continue to find that this is a serious concern, particularly in a circumstance where the Risk Premium model's ROE differs substantially from those of the DCF and CAPM models, such that the ROE produced in the second prong could fall within the applicable presumptively just and reasonable range from the first prong despite the challenged ROE falling outside that range or vice versa. To remedy this problem, we will impute the average width of the zones of reasonableness from the CAPM and DCF models onto the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. Doing so creates a zone of reasonableness for the ROE from the Risk Premium model, which can then be averaged with those of the other models in the first prong of the section 206 analysis. For example, if the Risk Premium model produces an ROE of 10% while the CAPM and DCF produce zones of reasonableness that average 400 basis points wide, the imputed zone of reasonableness for the Risk Premium would be 8% to 12%. We find that this is appropriate because the average width of those zones of reasonableness from models that

[198] *See* MISO TOs Rehearing Request at 51.

produce a zone of reasonableness is the best estimate of how far a zone of reasonableness should span from a single point like that produced by the Risk Premium model. Moreover, addition of the Risk Premium model to our analysis under the first prong of section 206 will not impact the size of the overall composite zone of reasonableness. Instead, it will merely reflect the Risk Premium model in the zone of reasonableness, based on equally weighted information from the models that directly produce a zone of reasonableness, allowing the Commission to use this model in both prongs. Accordingly, we find that it is appropriate to impute a zone of reasonableness for the Risk Premium model so that our ROE determinations under both prongs of section 206 are based on the same data and models.[199]

108. The Commission also expressed concerns regarding the regression analysis, noting specifically that the low number of observations could impact the reliability of the results.[200] Here we propose to use the individual cases for the Risk Premium analysis and not the average of the data from each year. Consequently, instead of nine observations in the regression analysis as proposed by the MISO TOs, there are 71 observations used in the First Complaint regression and 77 in the Second Complaint regression, leading to a much more robust and reliable result. Although the resulting regression coefficients are similar to those in the MISO TOs' calculations, we conclude that they are now based on more sound inputs and are thus more reliable.

109. The Commission cited use of settlements as a deficiency of the Risk Premium model. Parties may consider many factors when settling rate case proceedings. However, because of how directly ROEs affect rates, we conclude that parties engaged in arms-length negotiations seriously consider the ROE in the course of reaching settlements, even if the records in certain proceedings do not contain specific ROE calculations or testimony. Consequently, upon further consideration, we find that the ROEs from such settlements are reasonable to include in the Risk Premium analysis. However, because of the need to more precisely correspond the timing of ROEs to the corresponding bond yields, discussed below, we revise the bond yields (and corresponding risk premiums) to correspond to the six months preceding the offer of settlement and not Commission orders approving the settlements, as discussed below.

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[199] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 351 ("We would prefer to use the same models in the prong one and prong two analyses to ensure that our ROE determinations under each prong are based on the same data and models. It would not be logical to use different models and data sources to apply this same standard under the two prongs unless there is some compelling justification for the difference.").

[200] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 344.

This period, not the six months preceding Commission approval of settlements, best reflects when parties evaluated the ROE.

110. We also find that it is appropriate to eliminate certain cases from the Risk Premium analysis where the Commission did not consider the justness and reasonableness of the base ROE or the zone of reasonableness in making decisions. For example, we are excluding cases where transmission owners joined MISO and received the prevailing 12.38% ROE that was approved in 2002 without examination of the justness and reasonableness of that ROE. Similarly, in an order on a transmission rate incentives filing by PSEG,[201] the Commission explicitly stated that the ROE was beyond the scope of the proceeding.[202] In other cases, the MISO TOs' analysis unjustifiably contained multiple ROEs counted in the analysis from the same case.[203] We are also eliminating cases where the test period is in 2004, well before other proceedings on the list, given that there were likely other proceedings with test periods during 2004 and 2005 that were not included. We also propose, in order for the results of the Risk Premium analysis to be consistent with those of other models, to update the list of applicable cases to include data up through the conclusion of the test periods, which conclude June 2015 and December 2015 for the First Complaint and Second Complaint, respectively.

111. The Commission, in Opinion No. 569, also considered whether the bond yields used to determine the risk premium should more precisely align with test periods of Risk Premium cases. It found that, although a misalignment of the timing of bond yields and test periods might be acceptable when using the Risk Premium model corroboratively, using the model to set the actual ROE demanded correcting this imprecision. We continue to find that the risk premiums should not contain inconsistent dates for the ROEs and for the bond yields. Rather, they should be aligned by corresponding the ROE to the test periods on which it is based. For settlements, the relevant date is the date that parties file the settlement, not when the Commission approves it. Consequently, the six-month time period bond yields should be the six months preceding the settlements. Such information is reflected in the data in Appendix I.

112. In Opinion No. 569, the Commission also found that the record contained insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost

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[201] *PJM Interconnection, L.L.C. and Pub. Serv. Elec. & Gas Co*., 147 FERC ¶ 61,142, at P 48 (2014).

[202] However, the analysis does include those cases where the Commission made this finding, but the ROE was modified by settlement.

[203] *See* Appendix I. Note that when a case has multiple *different* ROEs, each of those are counted in the analysis.

of capital and make investment decisions. On rehearing, we find that investors do expect to earn a return on a stock investment that reflects a premium above the return they expect to earn on a bond investment,[204] and that the Risk Premium model is a method of estimating the premium over bond yields that investors require to invest in electric utility equities. In addition, as the Commission noted in Opinion No. 569, investors do observe regulatory ROEs and how changes in authorized ROE levels could affect utility earnings,[205] and while such considerations differ from the type of analysis employed by the Risk Premium model, it is a model that considers regulatory ROEs in estimating the premium that investors require to make equity investments instead of bond investments.

113. The Commission discussed in Opinion No. 569 that the MISO TOs' sample period, beginning in 2006, was substantially shorter than the period used by Dr. Morin, potentially leading to less credible results. We find that, although the data set for determining the risk premium would ideally be longer, that 10 years of data yielding over 60 observations is sufficient, noting that we are extending the sample periods slightly to the end of the updated test periods, as discussed above. Furthermore, the record lacks information on ROE proceedings whose order dates precede 2006.

114. The Commission also noted concerns, raised by Trial Staff, that the Risk Premium model should exclude periods of high volatility, specifically around the beginning of the Great Recession. We conclude that all periods should be included because the Risk Premium analysis should factor in periods where the bond yields change. A full sample size in this case *does* include the outlying periods because they reflect the Risk Premium at the time and such economic disturbances, which periodically recur.

VII. Expected Earnings

A. Opinion No. 569

115. In Opinion No. 569, the Commission determined that, in light of the record as supplemented after issuance of the Briefing Order, it is not appropriate to use the Expected Earnings model in our new base ROE methodology.[206]

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[204] *See, e.g.*, Morin at 108 ("[B]ased on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment.").

[205] Opinion No. 569, 169 FERC ¶ 61,129 at P 345.

[206] *Id.* P 200.

116. In particular, the Commission found that the record does not support departing from our traditional use of market-based approaches to determine base ROE.[207] The Commission determined that under *Hope*—which declares that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks"[208]—it is appropriate to consider the value of investment that is actually available to an investor in the market. Outside of the unlikely situation in which the market value and book value are exactly equal, investors do not have the opportunity to invest in an enterprise at its book value. Accordingly, the Commission deemed it most appropriate to exclude the Expected Earnings model, which relies on an enterprise's book value instead of the market value.

117. The Commission explained that the return on book value is not indicative of what return an *investor* requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined with respect to the current market price that an investor must pay in order to invest in the equity.[209] Specifically, the Commission found that the Expected Earnings model measures returns on book value, without consideration of what market price an investor would have to pay to invest in the relevant company, so it does not accurately measure the investor's expected returns on its investment, and, therefore, has been "thoroughly discredited."[210] In other words, the return on book value does not reflect "the return to the equity owner" that we must ensure is "commensurate with returns on investments in other enterprises," as *Hope* requires; therefore, the Commission found that this model is not useful in ensuring that these standards are satisfied.[211] Furthermore, the Commission found that there was insufficient record evidence to conclude that investors rely on the Expected Earnings analysis to estimate the opportunity cost of investing in a particular utility.[212]

118. The Commission also explained that, while it may be true that the Expected Earnings model does not involve the same complexities as the market-based approaches, this is because it does not reflect a utility's cost of equity.[213] Furthermore, applying the

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[207] *Id.* PP 201, 221.

[208] *Hope*, 320 U.S. at 603.

[209] Opinion No. 569, 169 FERC ¶ 61,129 at P 202.

[210] *Id.* PP 205, 221.

[211] *Id.* PP 202, 221-22.

[212] *Id.* P 210.

[213] *Id.* P 204.

Expected Earnings model in the cost-of-service context would lead to illogical results because a company in such a context would receive a higher overall return when it features a higher equity ratio, despite this indicating a lower risk (and thereby indicating a lower required rate of return by investors) than a company featuring a lower equity ratio.[214] Even though companies with more depreciated assets are generally of lower risk and therefore would merit a lower return, the Expected Earnings model would instead provide higher returns to such companies.[215]

B. Rehearing Requests

119. MISO TOs, Ameren, and Transource Energy seek rehearing of the Commission's decision to exclude the Expected Earnings model in determining base ROEs.[216] Transource Energy argues that the alleged flaws in the Expected Earnings approach actually become strengths when combined with the other models.[217]

120. Transource Energy asserts that the Expected Earnings model is actually market-based in the sense that market participants use it for investment decisions and that the Commission's definition of "market-based" is too narrow.[218] Furthermore, Transource Energy argues that the fact that the Expected Earnings model does not fit into the Commission's narrow definition of "market-based" highlights that it is needed to diversify the other models.[219] On the other hand, MISO TOs contend that the Expected Earnings approach helps ensure a base ROE that meets the requirements of *Hope* precisely because it is *not* market-based.[220]

121. According to MISO TOs, the record demonstrates that the Expected Earnings approach provides a unique perspective that no other model addresses and thus provides

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[214] *Id.* P 223.

[215] *Id.* P 224.

[216] Ameren Rehearing Request at 2, 4-6, 10-13, 23-25; MISO TOs Rehearing Request at 8, 13, 53-62; Transource Energy Rehearing Request at 3-4, 6, 8-10, 15-26.

[217] Transource Energy Rehearing Request at 23.

[218] *Id.* at 16.

[219] *Id.*

[220] MISO TOs Rehearing Request at 59-61.

a check on the market-based cost of equity approaches.[221] MISO TOs assert that, because regulators do not set the returns that investors earn in the capital markets, the Expected Earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.[222] In other words, MISO TOs explain, the Expected Earnings approach measures whether the allowed ROE is sufficient to assure confidence in the financial integrity of an enterprise so as to maintain its credit and attract capital.[223] In addition, MISO TOs state that, because it is not market-based, the Expected Earnings approach avoids the complexities, controversies, and limitations of capital market methods.[224] Transource Energy argues that the fact that Expected Earnings is not used independently of stock price is not disqualifying, because, under the four-model framework originally proposed, this approach actually works in concert with market-based methods like the included CAPM and DCF models.[225] According to MISO TOs, it is precisely because the Expected Earnings method examines the books of a proxy company rather than relying on market data that the approach provides a unique value in assessing whether a Commission-determined ROE meets the *Hope* and *Bluefield* standards.[226]

122. MISO TOs, Transource Energy, and Exelon assert that the Commission's finding that investors do not rely on the Expected Earnings analysis to estimate the ROE that a utility will earn in the future is contrary to the record in this proceeding and the record in the Commission's Notice of Inquiry proceeding[227] regarding its base ROE policy.[228] Transource Energy argues that Opinion No. 569 did not identify changed circumstances regarding how investors use the Expected Earnings and Risk Premium models and does

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[221] *Id.* at 59.

[222] *Id.*

[223] *Id.*

[224] *Id.* at 60 (citing MISO TOs, Supplemental Reply Brief, Docket No. EL14-12-003, App. 2 at 65 (filed Apr. 10, 2019) (McKenzie Supplemental Reply Brief Affidavit)).

[225] Transource Energy Rehearing Request at 24.

[226] MISO TOs Rehearing Request at 62.

[227] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (2019) (Base ROE NOI).

[228] MISO TOs Rehearing Request at 54-58; Transource Energy Rehearing Request at 18, 20-21, 24.

not find that investors no longer rely on them in evaluating investment decisions.[229] MISO TOs contend that testimony filed by multiple commenters in the Base ROE NOI proceeding, including MISO TOs, the New England TOs, the PJM TOs, and EEI, clearly demonstrates that investors do rely on the Expected Earnings analysis when making investment choices.[230] Exelon notes that the Commission stated in the Briefing Order that investors use the Expected Earnings model, but then later in Opinion No. 569 stated that there is insufficient evidence that investors rely on the Expected Earnings model. Exelon argues that the Expected Earnings model should be included in the ROE methodology even if only some investors rely on it.[231]

123. MISO TOs and Transource Energy also argue that the Commission cannot ignore evidence concerning the Expected Earnings model that it already found probative.[232] They contend that the Commission found the Expected Earnings approach to be reliable, corroborative evidence of the proper base ROE for electric utilities in Opinion Nos. 531, 531-B, and 551, and cannot now simply ignore evidence pertinent to the question before it with no basis for the sudden change.[233] Ameren contends that the Commission's assertion that the exclusion of the Expected Earnings model in Opinion No. 569 is not inconsistent with its determination in Opinion No. 551 is circular because the question on whether to exclude the model was never asked in Opinion No. 551.[234] Ameren explains that, in Opinion No. 551, the Commission relied on the Expected Earnings model to corroborate its finding and provides no explanation here for completely ignoring it. Ameren contends that this failure to at least consider the Expected Earnings model cannot be reconciled with the Commission's prior finding.[235] According to MISO TOs, the Expected Earnings analysis can inform whether the ROE produced by the Commission's methodology is appropriate, and ignoring pertinent evidence rooted in controlling Supreme Court precedent is arbitrary and capricious and not the product of reasoned

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[229] Transource Energy Rehearing Request at 21.

[230] MISO TOs Rehearing Request at 54-58.

[231] Exelon Rehearing Request, Docket No. EL14-12, at 12-13.

[232] MISO TOs Rehearing Request at 61-62; Transource Energy Rehearing Request at 18, 20-21, 24.

[233] MISO TOs Rehearing Request at 61.

[234] Ameren Rehearing Request at 25.

[235] *Id.*

decision-making.[236] Moreover, Ameren argues that this exclusion constitutes reversible error because the Commission never proposed the two-model approach in the Briefing Order or the Base ROE NOI, no party advocated for this approach in the instant docket, and the record does not support exclusion of the Expected Earnings model.[237]

124. MISO TOs and Transource Energy also assert that the Commission cannot deny the historical and regulatory acceptance of the Expected Earnings approach, as it was used in the Commission's prior "br + sv" approach for determining public utility ROEs and is closely related to the comparable earnings approach that originated in *Hope*.[238] Accordingly, they contend that the Commission can rely on the Expected Earnings model to determine whether a prospective base ROE meets the requirements of *Hope*, and to the extent a base ROE is inconsistent with the Expected Earnings analysis, significant explanation is needed as to how such a base ROE meets the requirements of *Hope*.[239] MISO TOs assert that the Commission should employ the Expected Earnings approach in setting the MISO TOs' base ROE or, failing that, should at least consider it as a check on the base ROE yielded by the Commission's alternative approach.[240]

C. Commission Determination

125. We deny requests for rehearing of the Commission's decision to exclude the Expected Earnings model from its base ROE analysis under section 206 of the FPA. As an initial matter, we note that the requests for rehearing largely repeat arguments parties previously made and which the Commission addressed in Opinion No. 569. Nothing in the rehearing requests persuades us to alter our decision here.

126. We are not persuaded by MISO TOs', Transource Energy's, and Exelon's arguments that investors rely on the Expected Earnings analysis to project utilities' earned ROE. While the record in this proceeding contains evidence that investors have access to data on earnings per book value, we continue to find that it lacks evidence that investors use such data to directly value equities, determine the cost of equity, or make investment decisions without consideration of the market price of the relevant equities.

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[236] MISO TOs Rehearing Request at 62.

[237] Ameren Rehearing Request at 23-24.

[238] MISO TOs Rehearing Request at 60; Transource Energy Rehearing Request at 20-21, 24-25.

[239] MISO TOs Rehearing Request at 60-61; Transource Energy Rehearing Request at 20-21, 24-25.

[240] MISO TOs Rehearing Request at 62.

As the Commission explained in Opinion No. 569,[241] investors cannot use the Expected Earnings model to directly determine the return they would earn from purchasing a company's stock, because the return estimated by that model is a return on the company's book value, not a return on the current stock price, which is what the investor must pay in order to invest in the company. Therefore, the returns estimated by the Expected Earnings model are divorced from the returns required by investors, because investors cannot purchase a company's stock at its book value (except in the very rare instance where a utility's market capitalization happens to exactly equal its book value). Similarly, we are not persuaded by MISO TOs' and Transource Energy's arguments that the Expected Earnings analysis is probative because the Commission, until Opinion No. 531, considered book value in the "br + sv" calculations. Our decision to exclude the Expected Earnings model from our base ROE analysis is not inconsistent with the Commission's prior consideration of book value in this context because such information was used in conjunction with, rather than instead of, the market price of the stocks.

127. Moreover, because the current market values of utility stocks substantially exceed utilities' book value, a utility's expected earnings on its book value will inevitably exceed the return that investors require in order to purchase the utility's higher-value stock, which means that the Expected Earnings model does not accurately measure the returns that investors require to invest in utilities.[242]

128. As explained in Opinion No. 569, the Commission has found that it is important to base the ROE on the returns currently required by investors, and the Expected Earnings model does not measure those returns. Specifically, since the 1980s, the Commission has rejected the use of returns on book value in determining the cost of equity and emphasized the importance of incorporating the market cost of equity when estimating ROEs because the market price is what investors must pay when making an investment and therefore is the basis on which investors measure the return on their investment.[243] As discussed in Opinion No. 569, this is also supported by a variety of academic literature indicating that the Expected Earnings model is not relied upon to directly estimate cost of equity.[244]

129. We are also not persuaded by MISO TOs' arguments that the Expected Earnings model should be used because it provides a unique, non-market-based perspective, and thus increases model diversity. Simply because a model increases model diversity does

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[241] Opinion No. 569, 169 FERC ¶ 61,129 at PP 201-202.

[242] *See id.* P 211.

[243] *See id.* PP 201 & n.426, 202, 216-18.

[244] *Id.* P 218.

not mean that it is necessarily appropriate to include, if the model is fatally flawed. This is the case because the returns on investment received depend on the market price that investors must pay to make their investment, which the accounting-based Expected Earnings model does not consider.

130. In response to MISO TOs' argument that the Expected Earnings model should be used because it avoids the complexities, controversies, and limitations of market-based methods, we stand by the Commission's explanation in Opinion No. 569[245] that the Expected Earnings model is simpler because it does not take into account the vitally important market cost of investing in a utility's equity. The market price that an investor must pay for an investment is a critical factor in determining a utility's cost of equity, and a model that ignores that factor is not useful in estimating cost of equity. The Expected Earnings model's relative simplicity is due to and invalidated by this deficiency.

131. Finally, we disagree with MISO TOs' and Transource Energy's arguments that the Commission cannot exclude the Expected Earnings model now because it already relied on the model as corroborative evidence in the underlying Opinion No. 551 in these proceedings. As the Commission explained in Opinion No. 569,[246] the Commission is now deciding whether to use the Expected Earnings model as a direct input in its ROE estimates—not merely whether to use it as corroborative evidence—and more convincing evidence is required to justify using the model as a direct input. We continue to find that parties have not supplemented the record with this more convincing evidence. We further note that no parties have explained or refuted the Commission's observation in Opinion No. 569 that the use of the Expected Earnings model in this context leads to illogical results of higher ROEs from companies with more equity in their capital structure or more depreciated assets.[247] Furthermore, Opinion No. 531, whose logic and methodology the Commission adopted in Opinion No. 551, was vacated by the court, such that neither form binding precedent.

132. While we do not adopt the Expected Earnings model in our revised methodology here for the reasons discussed above, we do not necessarily foreclose its use in future proceedings if parties can demonstrate that the concerns discussed above have been addressed.

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[245] *Id.* PP 203-204.

[246] *Id.* P 226.

[247] *See id.* P 223.

VIII. Weighting of Models

133. A number of parties made general comments that the Commission erred in overweighting the DCF and CAPM models by excluding the Risk Premium and Expected Earnings models. Section III above addresses such arguments.

A. Opinion No. 569

134. In Opinion No. 569, the Commission chose to use the DCF and CAPM models to determine base ROE, with both approaches being given equal weight. The Commission argued that it was inappropriate to include the Expected Earnings and Risk Premium models, as discussed above. By excluding them, the Commission effectively gave those models a weight of zero in its analysis under prongs one and two of section 206 of the FPA.[248]

135. The Commission also described why it would create the zones of reasonableness for each model based on the proxy company results for those individual models, average the midpoints/medians and zones of reasonableness bounds for the used models, and then determine the midpoints and applicable quartiles based on the averaged zones of reasonableness.[249] The Commission declined to adopt CAPs' proposed alternative of averaging the results for multiple models for each proxy group company before determining the applicable midpoint/median and zone of reasonableness. Further, the Commission noted that there was no record evidence of the models being applied this way in other regulatory proceedings or that the assumptions and structure of the DCF and CAPM models contemplate the isolation of results for specific proxy group companies as the CAPs' proposal would do.

B. Rehearing Requests

136. CAPs state that the Commission should not have equally weighted the results of the DCF and CAPM models in determining the composite zone of reasonableness. According to CAPs, the Commission disregarded the complainants' arguments regarding the "superiority of the DCF model, including evidence of broad industry recognition of the DCF model as the most appropriate way to determine allowable rates of return that meet the standards set out in *Hope* and *Bluefield*."[250] CAPs claim that the Commission relied more heavily on the MISO TOs' assertion that "investors base their decisions on factors more closely aligned with CAPM factors to disregard long-standing precedent

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[248] *Id.* PP 424-427.

[249] *Id*. PP 437-438.

[250] CAPs Rehearing Request at 85.

stating the superiority of the DCF model." CAPs argue that the equal weighting of the DCF and CAPM models is not supported by the record evidence or Commission precedent indicating that the DCF model is superior to the CAPM.

137. CAPs assert that the Commission did not explain its conclusion that equal weighting will reduce model risk associated with a given model more so than giving one model greater weight over the other. CAPs note that the DCF model has not become less reliable over the time that the Commission used it exclusively to determine cost of equity. Lastly, CAPs criticize the Commission for not considering Dr. Berry's rebuttal of the Briefing Order's basis for its new concerns regarding the DCF model's risk. According to CAPs, disregarding parties' arguments constitutes arbitrary and capricious decision making.[251] CAPs also aver that the Commission did not address Dr. Berry's testimony regarding the sequencing of model calculations.

138. Transource Energy argues that the Commission's rationale does not support a 50% weight for the DCF model. Previously with a four-model methodology, the DCF approach received a 25% weight. That approach led to a diverse methodology that minimized measurement errors. According to Transource Energy, assigning no weight to the Expected Earnings and Risk Premium models does not mean that the DCF model should be weighted equally with the CAPM.[252]

139. MISO TOs state that benchmark estimates of utilities' cost of equity using the Risk Premium and Expected Earnings models substantially exceed the Commission's composite midpoint ROE. In addition, MISO TOs state that anomalous capital market conditions undercut the validity of the DCF analysis where that model holds a 50% weight in deriving the composite zone of reasonableness from which the Commission derived the new base ROE it adopted in Opinion No. 569.[253] MISO TOs also note that the Commission previously agreed with Ms. Lapson's conclusion that using the DCF model does not satisfy *Hope* and *Bluefield*. MISO TOs assert that the DCF model does not satisfy *Hope* and *Bluefield* and therefore question the validity of the new ROE methodology when assigning a 50% weight to the DCF model. According to MISO TOs, the "same evidence of prevailing state ROEs on which the Commission relied in Opinion No. 551 undercuts the 50% weighting of the very same DCF analysis in Opinion No. 569."[254] They argue that the Expected Earnings and Risk Premium models can be used to show that the DCF model has a downward bias on the resulting base ROE.

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[251] *Id.* at 85-87.

[252] Transource Energy Rehearing Request, Docket No. EL14-12, at 21-22.

[253] MISO TOs Rehearing Request, Docket No. EL14-12, at 13.

[254] *Id.* at 18-19.

Furthermore, the Commission had previously noted that investors utilize the Expected Earnings and Risk Premium models.[255]

C. Commission Determination

140. We disagree with parties that assert that low reliability of the DCF model, the DCF model's similarity to the CAPM in terms of inputs, and the drawbacks of those two models as reasons against equal weighting. We also disagree with other parties that argue that the DCF should receive more weighting than other models given that it has been long-used by regulators. Parties arguing for less weighting do not suggest a specific alternative weighting scheme other than simply reducing the DCF's weight to less than 50% and overlook the distinctions between it and the other models. We disagree with contentions that, because the DCF gives results in these proceedings that are lower than those of the other models, that it should receive *less* weight than they do. The DCF model is clearly used by investors[256] and has been subject to extensive regulatory review and refinement. We also disagree with parties arguing for more weighting of the DCF model, because, as discussed above, we find substantial value in the CAPM and Risk Premium models and the evidence indicates that none of the three models is conclusively superior to any other. As discussed in this order and in Opinion No. 569, each model has unique aspects, and advantages and disadvantages that make it preferable to the other model in some respects, but not other respects.

141. We continue to find that the models used in our methodology should be afforded equal weighting to fully capture the model diversity that each brings. The evidence does not indicate that there is a clearly superior model for estimating cost of equity that should be given more weight than the others and we find that equally weighting the three models will reduce the model risk associated with any particular model more than giving one model greater weight than the other. Consequently, each model shall receive one-third weighting for both the first and second prongs of the section 206 analysis. The revised methodology ultimately addresses the concerns of certain commenters by reducing the weight attributed to the DCF model while expanding the diversity of the ROE methodology by including the Risk Premium model. We disagree with CAPs' assertion that the Commission in Opinion No. 569 failed to address Dr. Berry's concerns regarding model sequencing. The Commission provided a full and reasoned description of why it employed the sequencing order for ROE calculations that it had described in the Briefing Order.

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[255] *Id.* at 22.

[256] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 171, 426.

IX. Natural Break Analysis

A. Opinion No. 569

142. In Opinion No. 569, the Commission affirmed the use of a natural break analysis to both the high and low-end outlier screens but declined to set a specific threshold level or formula to use in the analysis. The Commission stated that any numerical outlier test will necessarily be somewhat arbitrary, and that the natural break analysis gives the Commission the flexibility to determine whether a given proxy group company is truly an outlier, or whether it contains useful information.[257]

B. Rehearing Requests

143. MISO TOs argue that, if the Commission retains the high-end outlier test and the natural break analysis, the high-end outlier threshold should be useable as evidence for retaining one or more cost-of-equity estimates that might otherwise be excluded because of a subjectively identified "natural break."[258]

144. MISO TOs contend that the natural break analysis utilized by the Commission has no foundation and invites arbitrary application. MISO TOs contend that the analysis is especially erroneous when applied to the high-end outlier test.[259] MISO TOs also argue that, if the Commission continues to apply a natural break standard to its low-end outlier test, it should not use this threshold to include companies that investors would ignore as unrepresentative of acceptable equity returns.[260]

C. Commission Determination

145. We deny MISO TOs' request for rehearing on the natural break analysis. We note that the high and low-end outlier tests are not meant to be purely statistical tests and refute MISO TOs' assertion that the natural break analysis is inherently flawed because it is subjective. Additionally, we clarify that the natural break analysis may be used as evidence for retaining one or more cost-of-equity estimates that might otherwise be excluded because of a high-end or low-end outlier test. Observations that are shown to be rational and not the result of error may still be included, even if they otherwise would fail one of the outlier tests. By the same logic, the natural break analysis can be used to

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[257] Opinion No. 569, 169 FERC ¶ 61,129 at PP 187-188.

[258] MISO TOs Rehearing Request at 76-77.

[259] *Id.* at 80-82.

[260] *Id.* at 83.

argue for exclusion of cost-of-equity estimates that do not fail either outlier test but can be shown to be irrational, anomalous, or the result of human error.

146. Model inputs can be flawed, due to incorrect inputs or the result of poor judgement by analysts. Such errors can improperly influence the analysis, especially when they affect estimates at the high and low end of the proxy group. As the Commission noted in the Briefing Order, one analyst's error involving the growth projections for Portland General Electric Company reduced the overall Reuters consensus projected short-term percentage growth in earnings from 10.96% to 7.8%.[261] This case illustrates the fallibility of model inputs and the importance of having a natural break analysis to enable the Commission to use its discretion with respect to high or low values.

X. High-End Outlier Test

A. Opinion No. 569

147. In Opinion No. 569, the Commission adopted the high-end outlier test proposed in the Briefing Order, which excludes from the proxy group any company whose cost of equity estimated under the model in question is more than 150% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a natural break analysis. The Commission noted that financial metrics for individual utilities can fluctuate dramatically, potentially affecting ROEs that use midpoints as measures of central tendency and found that it was appropriate to eliminate members of the proxy group whose ROEs are unreasonably high.[262]

B. Rehearing Requests

148. MISO TOs argue that the Commission should not adopt any high-end outlier test. MISO TOs argue that the high-end outlier test artificially narrows the zone of reasonableness. MISO TOs further argue that if the Commission retains the high-end outlier test, it should be used only as a rebuttable presumption, and then applied only to the highest of the median values produced by the analyses used.[263]

149. MISO TOs further argue that, even if the Commission retains the high-end outlier test, it should not be applied to the two-step DCF analysis. MISO TOs argue that,

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[261] Briefing Order, 165 FERC ¶ 61,118 at P 19 n.95 (*Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 47).

[262] Opinion No. 569, 169 FERC ¶ 61,129 at P 179.

[263] MISO TOs Rehearing Request at 70-73.

because the median of the two-step DCF may be unreliable or produce unjust and unreasonable results, its use in the high-end outlier test is similarly unreliable.[264]

150. Transource Energy contends that there is no evidence that a logical high-end outlier test exists that would apply generically as the low-end outlier test does. Transource Energy argues that a generic exclusion based on distance from the median may reject potentially useful observations. Transource Energy contends that, if the Commission were to utilize a high-end outlier test, the Commission should treat the test as a high-end cap on the result and not a high-end exclusion of data points.[265]

151. Exelon contends that the high-end proxy group utilities that are excluded under the high-end outlier test represent actual data regarding utilities of a similar risk profile, and thus application of the test changes the range of studied ROEs from those that actual investors consider in the market.[266]

C. Commission Determination

152. We grant in part and deny in part the requests for rehearing on the high-end outlier test. While the high-end outlier test uses the median, it is not solely meant to serve as a statistical test to remove proxy group companies that are not representative of typical utilities. Rather, the high-end outlier test, when coupled with a natural break analysis, screens for observations that are irrationally or anomalously high.

153. As an initial matter, we note that some parties have characterized the high-end outlier test as stricter than it is. As noted above, the high-end outlier test is subject to a natural break analysis, meaning observations that are shown to be rational and not the result of error may still be included, even if they are over the threshold.

154. However, we find that it is appropriate to modify the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median—as opposed to the 150% of the median threshold applied in Opinion No. 569—result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. The high-end outlier test is the Commission's best attempt to use an objective test to identify proxy group ROEs that are irrationally or anomalously high because, for example, they are the result of atypical circumstances that are unrepresentative of the subject utility's risk profile or otherwise likely to be in error.

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[264] *Id.* at 74-76.

[265] Transource Energy Rehearing Request at 28-29.

[266] Exelon Rehearing Request at 13-14.

We recognize such a test with a bright-line threshold could inappropriately exclude ROEs that are rational and not anomalous for the subject utility. In recognition of this risk, we find that increasing the threshold for the high-end outlier test to 200% of the median result of all of the potential proxy group members in the applicable model[267] is appropriate because it will reduce the risk that such rational results are inappropriately excluded. However, as we note above, the continued application of the natural break analysis will still allow the exclusion of ROEs that are truly irrational or anomalously high, even if they fall under the threshold set by this high-end outlier test.

155. While we are modifying the high-end outlier test to increase its exclusion threshold, we find that it is still appropriate to maintain the test as an objective check to help identify observations that are irrationally or anomalously high. This is especially true because we will continue to use the midpoint as a baseline to determine region-wide ROEs for groups of utilities and potentially flawed high-end observations from the proxy group play a large role in an ROE analysis that uses the midpoint. While we note that the addition of the Risk Premium model to the analysis diminishes the impact of outliers, we do not find this to be enough to warrant removal of the high-end outlier test entirely. Thus, the high-end outlier test continues to apply, but with the modification described above.

XI. Low-End Outlier Test

A. Opinion No. 569

156. In Opinion No. 569, the Commission adjusted the low-end outlier test to eliminate from the proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium. The Commission found that it was necessary to exclude ROEs whose yield was "essentially the same expected return" as debt in order to determine the low end of the zone of reasonableness. The Commission noted that the risk premium that investors demand changes over time and found that using 20% of the CAPM risk premium struck an appropriate balance of accounting for the additional risk of equities over bonds while not inappropriately excluding proxy group members whose ROE is distinguishable from debt.[268]

[267] The high-end outlier test only applies to the DCF model and CAPM because they utilize results of the relevant analysis applied to a proxy group, while the Risk Premium model is derived from actual ROEs.

[268] Opinion No. 569, 169 FERC ¶ 61,129 at PP 184-185.

B. Rehearing Requests

157. RPGI argues that the Commission has not justified revising the low-end outlier test, and specifically has not supported including 20% of the CAPM risk premium.[269]

158. CAPs contend that using the Baa bond yield index is an inappropriate way to determine whether a ROE is an unreliable low-end outlier. CAPs further contend that this is inconsistent with Commission precedent, noting the Commission's explanation in Opinion No. 489 that, when applying a low-end outlier test, "it is appropriate to consider the company's own cost of debt, not the composite debt of the proxy group."[270] CAPs note that applying this to a company's own cost of debt results in OGE Energy being added back into the proxy group for the Second Complaint.[271]

159. CAPs similarly argue that the Commission's use of the risk premium should be rejected. However, CAPs contend that, if the Commission continues to utilize a risk premium, it should instead be 20% of the difference between the CAPM equity market return and the Moody's Baa utility bond yield.[272]

160. MISO TOs argue that the Commission erred in adopting its low-end outlier test and should instead apply the low-end methodology described by Mr. McKenzie in order to account for the inverse relationship between equity risk premiums and bond yields.[273]

C. Commission Determination

161. We deny the requests for rehearing on the low-end outlier test. We are not persuaded by RPGI's and MISO TOs' assertions that the Commission erred in adopting its low-end outlier test based on 20% of the CAPM risk premium. Likewise, we disagree with CAPs that the low-end outlier test is inconsistent with prior Commission precedent. As the Commission noted in Opinion No. 569, the Commission has applied this test differently in the past and did not always examine a company's own cost of debt.[274]

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[269] RPGI Rehearing Request at 27-31.

[270] CAPs Rehearing Request at 88-90.

[271] *Id.* at 94.

[272] *Id.* at 90-92.

[273] MISO TOs Rehearing Request at 83-84.

[274] Opinion No. 569, 169 FERC ¶ 61,129 at P 389 n.783 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 123).

The Commission also found that "using the specific bond yield for each company . . . renders [the calculations] (and the resulting ROE) less predictable, as the credit ratings for individual companies are likely more volatile than the generic corporate rate Baa credit rating."[275] Thus, we reiterate our finding here that applying the low-end outlier test to the Baa bond yield is appropriate. We also decline to adopt CAPs' proposal to instead use 20% of the difference between the CAPM equity market return and the Moody's Baa utility bond yield, and affirm our use of the United States 30 year treasury note in calculating the CAPM equity risk premium. There is no compelling evidence that, with respect to determining the risk premium, using Moody's Baa utility bond yields is superior to the treasury yields. Treasury yields are generally more stable than corporate bond yields, which here increases model stability. Furthermore, the low-end outlier test already incorporates the Moody's Baa utility bond, to which it adds 20% of the risk premium to determine the test. Using it twice would be unnecessarily duplicative. Additionally, we note that the risk premium is meant to reflect the opportunity cost of investing in equities generally, and therefore, using an industry-specific measure to determine the low end of the risk premium's range is inappropriate.

162. We also decline to adopt MISO TOs' proposed methodology. Opinion No. 569's proposed low-end outlier test methodology recognizes the dynamic nature of risk premiums without eliminating numerous proxy group members as the MISO TOs' methodology might in certain conditions. In Mr. McKenzie's example, use of his proposed test leads to the exclusion of six rather than three companies, the upper three of which feature ROEs very close to those of other companies.[276] This indicates that MISO TOs' proposed outlier test is excluding more than just outliers, systematically adding a significant upward bias to the DCF results.

XII. Consideration of State ROEs

A. Opinion No. 569

163. The Commission found that the ROE determination in these proceedings did not need to consider state-authorized ROEs. The Commission agreed with MISO TOs that there are material differences between state and Commission ROEs. As a result, the Commission stated that it would only consider state-authorized ROEs on a case-by-case

[275] *Id.*

[276] Appendix 3 to McKenzie Affidavit in MISO TOs Initial Brief.

basis to the extent that the state-authorized ROEs demonstrate that the results of the Commission's CAPM and DCF analyses are substantially excessive or deficient.[277]

B. Requests for Rehearing

164. Ameren, MISO TOs, and Transource Energy all note that the Commission stated in Opinion No. 569 that its new ROE approach would consider state-authorized ROEs, but argue that, despite the express inclusion, the Commission failed to perform this check. These parties assert that the Commission has previously found that transmission ROEs generally should be higher relative to those of distribution-only and integrated electric utilities. These parties claim that the Commission disregarded record evidence of state-authorized ROEs above 9.88%, and argue that this evidence demonstrates that, relative to the risk to transmission, 9.88% is an insufficient level of return to attract capital under the *Hope* and *Bluefield* standards.[278]

165. According to MISO TOs, the Commission's findings that transmission is riskier than state-regulated retail utility operations and that the MISO TOs are at least as risky as integrated utilities require that the MISO TOs' base ROE be somewhat higher than most, if not all, contemporaneous state-authorized ROEs. MISO TOs state that all state ROEs allowed during the Docket No. EL14-12 study period exceeded the DCF midpoint. Indeed, even the midpoint of all state-allowed ROEs, 9.95%, exceeded the base ROE of Opinion No. 569, and 31 out of 58 state-authorized ROEs for integrated utilities were between 10% and 10.4%.[279]

166. MISO TOs argue that *Emera Maine* did not disturb the Commission's finding in Opinion No. 531-B that the proper use of state commission ROEs is to compare the "significant number of state commission-authorized ROEs to the midpoint produced by the application of the Commission's traditional methodology" and determine whether "their levels, relative to each other, were illogical in light of the record evidence concerning the comparative risks of state-level electric distribution and interstate electric transmission." They contend that evidence of prevailing state ROEs during the study period indicates that a base ROE equal to or higher than 10.32% is justified.[280] They state that other estimates of the MISO TOs' cost of equity support the same inference, and thus support the Opinion No. 551 outcome. They note that: the Commission's

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[277] Opinion No. 569, 169 FERC ¶ 61,129 at P 363.

[278] Ameren Rehearing Request at 8-10; MISO TOs Rehearing Request at 14-16; Transource Energy Rehearing Request at 10-14.

[279] MISO TOs Rehearing Request at 33.

[280] *Id.* at 33-34 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 88).

application of the CAPM in Opinion No. 569 resulted in a midpoint of 10.45%; the Commission in Opinion No. 551 accepted a Risk Premium estimate of 10.36% and an Expected Earnings midpoint estimate of 11.99%; and the Briefing Order presented a restated Expected Earnings analysis with a midpoint of 11.41%, and repeated the Risk Premium estimate of 10.36%.[281]

C. Commission Determination

167. As an initial matter, the modifications made in this order to the ROE determination methodology result in higher ROEs in these proceedings, at least in part rendering moot concerns about the relative levels of state-authorized ROEs for integrated utility operations versus Commission-authorized transmission ROEs. Furthermore, the 10.02% ROE resulting from this order exceeds the average ROEs in the MISO TOs' analysis for both vertically-integrated utilities and for all utilities.[282] Moreover, MISO TOs' comparison of Commission ROEs in this proceeding with state ROEs over a two-year period, concluding in 2014, before the test period in this proceeding, is inappropriate. As illustrated by the fact that the DCF and CAPM midpoint ROEs in the Second Complaint are lower than those in the First Complaint, capital market conditions can change over time, rendering past comparisons obsolete. The ROEs in this proceeding must reflect capital market conditions during the first half of 2015 for the First Complaint and the second half of 2015 for the Second Complaint, so comparisons to state ROEs during the preceding two years are of limited value. We also continue to find that state-authorized and Commission-authorized ROEs are conceptually distinct and do not necessarily need to be aligned. In Opinion No. 569, the Commission indicated that state-authorized ROEs would only be considered on a case-by-case basis and not as a necessary part of the Commission's ROE methodology, and accordingly we disagree that we were required to consider state-authorized ROEs as part of the ROE determination in this proceeding. Although the Commission may consider a wide range of evidence in its ROE determinations, it is not legally required to base its jurisdictional transmission ROE determinations on the ROEs determined by state utility commissions. Furthermore, that the Commission relied on state ROEs corroboratively in the vacated Opinion No. 531 and in Opinion No. 551 that was pending before the Commission on rehearing, does not create binding precedent that the Commission must justify departure from in its finding that it will not necessarily consider state ROEs when determining transmission ROEs.

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[281] *Id*. at 34.

[282] *See* MTO-20 at 1-2.

XIII. Use of the Midpoint

A. Opinion No. 569

168. The Commission stated that it will continue to use the midpoint to determine the central tendency of the zone of reasonableness in cases involving an RTO-wide ROE, consistent with the policy set forth in the *MISO Remand Order*,[283] and that intervenors did not present a compelling reason as to why that policy should not be applied in this ROE proceeding.[284] The Commission explained that MISO TOs are a diverse set of companies and the central value becomes an important part in determining RTO-wide ROE.[285] The Commission also found that the high and low ends of the DCF and CAPM zones of reasonableness were representative of the highest and lowest risk profiles among the MISO TOs.[286]

B. Requests for Rehearing

169. CAPs contend that the Commission erred in using the midpoint, rather than the median, as the measure of central tendency for the ROE under the second prong of the section 206 analysis. CAPs point out that the Commission has found that the median best represents the central tendency in a skewed distribution[287] and is "less affected by extreme numbers than the midpoint."[288] CAPs find unpersuasive the Commission's finding in Opinion No. 569 that the companies that set the high and the low end of the zone of reasonableness in Opinion No. 569's DCF and CAPM analyses have similar risk

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[283] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at PP 9-10 (2004) (*MISO Remand Order*), *aff'd*, *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[284] Opinion No. 569, 169 FERC ¶ 61,129 at P 409.

[285] *Id.* PP 410-411.

[286] *Id*. PP 412-413.

[287] CAPs Rehearing Request at 83 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 114-116, *reh'g denied*, 137 FERC ¶ 61,016 (2011) (SCE Rehearing), *aff'd in relevant part sub nom*. *S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (D.C. Cir. 2013); *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002). *See also Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC at 61,427, *aff'd* Opinion No. 414-B, 85 FERC ¶ 61,323 (1998), *rev. denied sub nom.*, *N.C. Util. Comm'n v. FERC*, 203 F.3d 53 (D.C. Cir. 2000)).

[288] *Id.* (citing SCE Rehearing, 137 FERC ¶ 61,016 at P 19).

profiles to the MISO TOs. CAPs contend that this explanation misses the point because, even if the risk profile of the proxy group companies setting the high and low ends of the DCF and CAPM zones of reasonableness are within that wide variation, the averaged DCF and CAPM midpoints do not correspond to the highest and lowest cost of capital among Respondent MISO TOs. Consequently, according to CAPs, using the highest and lowest ROEs in the DCF and CAPM zones to calculate the presumptively just and reasonable zones or to determine the replacement ROE does not result in emphasizing the full range of the individual MISO TOs' costs of equity to serve a diverse group of TOs.

170. CAPs state that the premise for use of the midpoint is counter-factual because there is no direct correlation between credit ratings and the utilities setting the upper and lower bounds of the composite zone of reasonableness and the highest and lowest credit ratings of the MISO TOs.[289] CAPs state that the Commission dismissed this concern on the basis that such lack of correlation is not a problem because the credit ratings of the proxy companies that turn out to define the DCF-CAPM combined range are within the MISO TOs' wide variation of credit ratings.

C. Commission Determination

171. We disagree with arguments on rehearing that the Commission erred in continuing to use the midpoint as the measure of central tendency when establishing an ROE for groups of utilities like the MISO TOs. Such arguments fail to provide a basis for reversing a court-affirmed finding that it is just and reasonable to use the midpoint as the measure of central tendency for groups of utilities.[290] Additionally, the Commission described in great detail the general correspondence between the credit rating of proxy group companies and those at the high and low end of the zone of reasonableness, even if this examination was not specific to the MISO TOs.[291] The fact that the MISO TOs' highest and lowest credit ratings do not fully correspond to the high and the low ends of the CAPM and DCF zone of reasonableness in this particular proceeding does not change the fundamental purpose of applying the midpoint to groups of utilities, which is capturing a variety of risks that they feature.

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[289] *Id.*

[290] *See Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d at 1004, 1010.

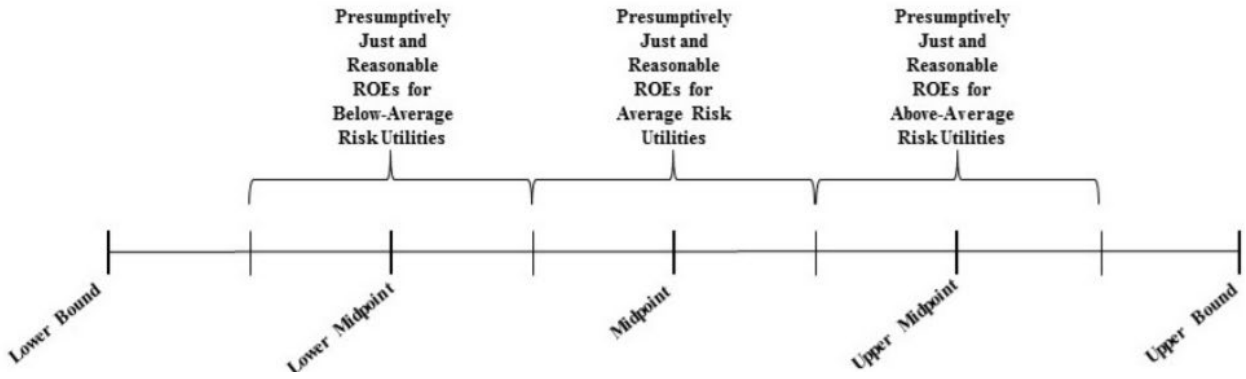
[291] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 412.

XIV. Ranges of Presumptively Just and Reasonable ROEs

A. Opinion No. 569

172. In Opinion No. 569, the Commission adopted the use of ranges of presumptively just and reasonable ROEs based on the risk profile of a utility or group of utilities to inform the Commission's decision of whether an existing ROE has become unjust and unreasonable, as proposed in the Briefing Order.[292] Specifically, the Commission found that, for average risk utilities, the presumptively just and reasonable range is the quartile of the overall composite zone of reasonableness centered on the central tendency of the overall zone of reasonableness; for below average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of reasonableness; and for above average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness. These ranges of presumptively just and reasonable base ROEs located within the overall composite zone of reasonableness are illustrated below.

Figure 1: Zone of Reasonableness Quartiles



173. In constructing the ranges of presumptively just and reasonable base ROEs, the Commission noted its precedent that the midpoint of the overall zone of reasonableness is a good starting place for the placement of an ROE and found that the measure of central tendency for the entire zone of reasonableness should be the starting point for identifying the range of presumptively just and reasonable base ROEs for utilities with an average risk profile.[293] The Commission then found that, similarly, the starting points for identifying the ranges of presumptively just and reasonable base ROEs for utilities with above or below average risk profiles should be the historic measures of central tendency

[292] *See id.* P 57.

[293] *Id.* P 63 (citing *Emera Maine*, 854 F.3d at 27 (citing *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1213 (D.C. Cir. 1991)) ("We have noted that the midpoint is a good 'starting place' for the placement of the ROE.")).

of the upper and lower halves of the zone of reasonableness, respectively – their respective midpoints.[294] The Commission explained that it was logical for the end points of those ranges to not be closer to the starting points for the ranges of utilities with different risk profiles than they are to their own starting point. Applying this rationale, the Commission found that the range within the overall zone of reasonableness that best represents presumptively just and reasonable ROEs for average risk utilities is the quartile of the zone of reasonableness centered on the central tendency of the entire zone of reasonableness, while the ranges within the overall zone of reasonableness that best represent presumptively just and reasonable ROEs for above- and below- average utilities are the quartiles centered on the central tendencies of the upper and lower halves of the zone of reasonableness, respectively.[295]

174. The Commission explained that adopting the use of ranges of presumptively just and reasonable base ROEs was necessary to satisfy the requirements of the *Emera Maine* decision, which found that the Commission's decision that "a single ROE analysis generating a new just and reasonable ROE necessarily proved that the Transmission Owners' existing ROE was unjust and unreasonable" is contrary to the FPA.[296] Such ranges were also necessary, the Commission reasoned, because, according to the *Emera Maine* decision, "the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE," and thus that a finding that a particular ROE is just and reasonable, "standing alone, 'does not amount to a finding that every other rate of return'" is not just and reasonable.[297] The Commission found that, in light of these findings, the Commission's explanation of the particular circumstances that support an explicit finding that the existing ROE has become unjust and unreasonable must include a showing that the existing ROE is now outside some range of potentially just and reasonable ROEs within the zone of reasonableness for the public utility at issue, in light of our estimate of the current market cost of equity. Alternatively, the Commission found that it could find that it could determine that other evidence

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[294] *Id.* (citing *Emera Maine*, 854 F.3d at 30 (citing *Tenn. Gas Pipeline*, 926 F.2d at 1213) ("[Where] the utility at issue was riskier than the proxy group . . . the midpoint of the upper half was 'an obvious place to begin.'"); *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, at PP 270, 273 (2017) (setting ROE at the "measure of central tendency of the lower half of the zone of reasonableness . . . [g]iven [the utility's] low level of risk as compared to the proxy group.")).

[295] *Id.*

[296] *Id.* P 57 (citing *Emera Maine*, 854 F.3d at 26).

[297] *Id.* (citing *Emera Maine*, 854 F.3d at 26 (quoting *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 857 (D.C. Cir. 1983))).

convincingly demonstrates that the existing ROE is unjust and unreasonable despite it falling within that range.[298]

175. The Commission also explained that the base ROEs that fall within the applicable range of presumptively just and reasonable base ROEs will be presumed to be just and reasonable, and those that fall outside of the applicable range will be presumed to be unjust and unreasonable.[299] The Commission further found that those presumptions would only be rebuttable presumptions because the ultimate determination of whether an existing ROE is unjust and unreasonable still "depends on the particular circumstances of the case."[300] The Commission noted that other evidence regarding the particular circumstances of the case could rebut a presumption that applies, such as evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, and testimony regarding the effects of rates on customers.[301]

B. Rehearing Requests

176. MISO TOs argue that, while the concept of a range of presumptively just and reasonable ROE values has merit, there are problems with the quartile approach used in Opinion No. 569. First, MISO TOs contend that the Commission never reconciles its concept of risk-associated sub-ranges with its long-standing rationale for using the midpoint to establish base ROEs for groups of utilities (i.e., to reflect such a group's broad range of risks). They contend that, while the midpoint rationale dovetails with *Emera Maine*'s recognition that "the zone of reasonableness creates a broad range of potentially lawful ROEs," the quartile approach of Opinion No. 569 does not. MISO TOs state that the Commission's historical reference to the midpoint explicitly recognizes the need to reflect the full range of required returns for a proxy group determined to be representative of a group of utilities such as the MISO TOs. But they contend that the Commission's attempt to further parse this composite zone uses an unexplained and arbitrary notion of relative risk based on arbitrary quartiles and is inconsistent with the Commission's own rationale for referencing the midpoint. Moreover, they assert that, as applied in Opinion No. 569, the effort lacks any foundation in case-specific evidence.[302]

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[298] *Id.* PP 61-62.

[299] *Id.* P 85.

[300] *Id.* P 68 (citing *Emera Maine*, 854 F.3d at 23).

[301] *Id.*

[302] MISO TOs Rehearing Request at 29.

177. In addition, MISO TOs contend that the Commission's new approach is inconsistent with the logic it uses to select the proxy group. They state that the proxy group is assembled using criteria which limit the proxies to companies that are considered to present investment risks comparable to those of the utility or group of utilities whose rates are at issue. Nevertheless, they argue, the Commission's quartile approach effectively truncates the zone of reasonableness by omitting from consideration the top one-eighth and the bottom one-eighth of the composite zone. They argue that the Commission's reasoning departs without explanation from the principle that every value in the zone of reasonableness is potentially a lawful ROE.[303]

178. MISO TOs further argue that the Commission derives its quartiles from the composite range of DCF and CAPM results but overlooks that different proxy companies' results are found at the low end, the middle, and the high end of each of the two analyses on which the Commission relies. Thus, MISO TOs assert, one or more proxies that fall within the "above average risk" quartile in the results of the DCF model appear in a different quartile of the CAPM results. MISO TOs argue that the Commission therefore cannot rationally distinguish "high risk" proxy companies from "low risk" proxies in its composite zone. They contend that the Commission has not provided an economic or financial rationale for the quartile approach.[304]

179. With regard to the Second Complaint, MISO TOs contend that there likewise is no need for a new ROE methodology to justify dismissal of the Second Complaint. According to MISO TOs, the upper midpoint of the Commission's IBES-based DCF analysis for the Second Complaint study period is only 9.83%, reflecting—just as in the First Complaint—anomalous capital market conditions. But they assert that alternative benchmark estimates and state ROE data demonstrate, as the Presiding Judge found, that the DCF outcome is unreliable. They argue that midpoint CAPM and Expected Earnings estimates (10.49% and 11.41%, respectively), as well as a Risk Premium estimate of 10.36%, establish that the Second Complaint record does not support a finding that the 10.32% base ROE determined in Opinion No. 551 was unjust and unreasonable for the Second Complaint study period.[305] They state that state-authorized ROEs for lower-risk integrated and distribution utilities further corroborate that conclusion, citing witness Lapson's national survey of state regulatory decisions in 2014-2015 that authorized base ROEs of 10% or more for retail utility operations in states within the MISO region.[306]

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[303] *Id*. at 29-30.

[304] *Id.* at 30.

[305] *Id*. at 35.

[306] *Id*. at 35-37.

180. MISO TOs state that, if the Commission continues to pursue Opinion No. 569's approach to using ranges of presumptively just and reasonable ROEs based on a portion of the zone of reasonableness, two alternative approaches would remedy the principal shortcoming of the Commission's quartile approach (i.e., its excision of the highest and lowest eighths of the composite zone). They state that this can be resolved either by dividing the entire zone of reasonableness into equal thirds, rather than quarters, or by using the upper and lower midpoints of the zone of reasonableness to segregate the three portions of the zone.[307]

181. Exelon argues that the Commission's ranges of presumptively just and reasonable ROEs are too narrow. Exelon contends that the Commission does not explain why it makes sense to treat only 25% of the range of investor expectations that is developed by the financial models as presumptively just and reasonable. Exelon asserts that the Commission already identifies a screened peer group with comparable risk to the subject utility when it selects a proxy group, and that it is unreasonable to adjust again for that same risk in determining quartiles for ranges of presumptively just and reasonable ROEs.[308]

182. Exelon also argues that there is no rationale for placing the top eighth and bottom eighth of the zone of reasonableness out of the ranges of presumptively just and reasonable ROEs. Exelon further contends that, while quartiles result in an even division, the Commission never justifies its use of quartiles.[309] In addition, Exelon asserts that the Commission's ranges of presumptively just and reasonable ROEs are so narrow that small proxy group changes, such as the exclusion of a proxy group company or a change in the performance of a particular proxy group company, could result in a utility's ROE changing from presumptively just and reasonable to presumptively unjust and unreasonable. Exelon argues that this will create rate instability that will chill investment.[310]

183. Exelon also disagrees with the Commission's conclusion in Opinion No. 569 that the use of ranges of presumptively just and reasonable ROEs does not change the burdens that apply in the context of section 206 complaints. Exelon contends that, under Opinion No. 569, an average risk utility whose base ROE is above the applicable range of presumptively just and reasonable ROEs bears the burden of overcoming a presumption that its ROE is unjust and unreasonable, which removes the burden on the complainant to

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[307] *Id*. at 38.

[308] Exelon Rehearing Request at 8-10.

[309] *Id.* at 10-11.

[310] *Id.* at 15-17.

demonstrate that such an ROE is unjust and unreasonable. Exelon asserts that this departure from section 206 is especially unreasonable because the upper and lower eighths of the zone of reasonableness can never be presumptively just and reasonable.[311]

184. Transource Energy argues that the full zone of reasonableness represents the broad range of potentially reasonable ROEs, as the court stated in *Emera Maine*, and thus that full zone presents the best evidence of what is a potentially lawful ROE, not a subzone within the overall zone. Transource Energy contends that the full zone of reasonableness already accounts for risk and contains comparable and representative companies. Transource Energy asserts that the Commission does not provide evidence justifying that there are identifiable distinctions in the risk profiles of firms that constitute the proxy group which fall neatly into quartiles. Transource Energy further argues that the Commission's exclusion of the top and bottom eighths of the zone of reasonableness ignore otherwise valid ROE estimates in the ranges of presumptively just and reasonable ROEs.[312]

185. CAPs argue that *Emera Maine* did not require the Commission to adopt a new methodology, but only to better explain Opinion No. 531's finding that the New England TOs' existing 11.14% base ROE was unjust and unreasonable.[313] If the Commission decides to adopt a new methodology, CAPs argue that the quartile approach is flawed. CAPs argue that the presumptively just and reasonable zones raise the customers' burden of proof to challenge ROEs that may have become unjust and unreasonable. CAPs assert that the presumptively just and reasonable zones are contrary to the customer protection principles embodied in the FPA and introduces an unlawful asymmetry between rate increases sought by utilities under section 205 of the FPA and rate reductions sought by customers under section 206 of the FPA.[314]

186. If the Commission keeps the presumptively just and reasonable zones, CAPs argue that the Commission should narrow these zones. They contend that the quartile approach results in unnecessarily broad presumptive zones. They reiterate their argument from their initial briefs that the Commission could narrow the presumptive immunity zones by, for example, establishing five risk groups:ver y-low risk; moderately low risk; average risk; moderately high risk; and very high risk. Under this approach, CAPs argue, the zones would be narrower, representing sextiles rather than quartiles of the composite

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[311] *Id.* at 19-22.

[312] Transource Energy Rehearing Request at 30-35.

[313] CAPs Rehearing Request at 12-16.

[314] *Id.* at 16.

range.[315] Regarding the Commission's statement that the quartile approach using three risk groups strikes an appropriate balance between the interests of customers and utilities, CAPs argue that the very establishment of presumptively just and reasonable zones already tilts the balance of interests in favor of shareholders.[316]

187. CAPs argue that the Commission did not explain why the "traditional" starting point for assessing risk is relevant or even preferable to a narrower and more precise definition of risk that would better protect customers. CAPs argue that it is possible to start the risk assessment at a point of central tendency within any sub-range of the zone of reasonableness. Furthermore, CAPs assert that the proximity of potentially lawful ROEs to the just and reasonable ROE does not render these ROEs presumably just and reasonable (i.e., ROEs within the zone of reasonableness that are close to the just and reasonable ROE may be a little less unjust and unreasonable, but remain unjust and unreasonable nonetheless). They argue that the courts have ruled that the just and reasonable standard does not permit "even a little unlawfulness."[317]

188. CAPs also argue that the notion of presuming the justness and reasonableness of ROEs close to the lawful ROE runs afoul of multiple rulings made by the court in *Emera Maine*: (1) it is arbitrary and capricious to assume that there are only three possible stopping points—lower midpoint, midpoint, and upper midpoint—on the continuum of "potentially just and reasonable" ROEs that lie within the range of adopted proxy results; (2) the fact that a rate falls within the zone of reasonableness does not establish that the rate is the just and reasonable rate for the utility at issue; and (3) whether a rate, even one within the zone of reasonableness, is unlawful depends on the particular circumstances of the case, and, therefore, requires that a numerical comparison of model results to an existing ROE be accompanied by a narrative explanation of what made a difference between the two unreasonable.[318] CAPs argue that, if the proximity of an ROE to the just and reasonable ROE does not conclusively prove the justness and reasonableness of an ROE, then such proximity cannot be used to infer that all ROEs that are close to the just and reasonable ROE within a certain range "may" be just and reasonable.[319]

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[315] *Id.* at 16-17.

[316] *Id*. at 17.

[317] *Id.* at 18 (citing *Consumers Fed'n of Am. v. FPC*, 515 F.2d 347, 358 n.64 (D.C. Cir. 1975) (quoting *FPC v. Texaco*, 417 U.S. 380, 399 (1974))).

[318] *Id*. at 18-19.

[319] *Id*. at 19-20.

189. RPGI asserts that, for average risk utilities, the midpoint of the zone of reasonableness is what the existing ROE must be compared to—not a range of presumptively just and reasonable ROEs—and any existing ROE that exceeds that midpoint should be presumed unjust and unreasonable. RPGI also contends that the use of ranges of presumptively just and reasonable ROEs contravenes the FPA's consumer protection purpose because it can insulate an existing ROE from a section 206 challenge even if, for example, an existing ROE for an average-risk group of utilities exceeds the midpoint. In addition, RPGI argues that, while the Commission states that the ranges of presumptively just and reasonable ROEs create only a rebuttable presumption, it is difficult to imagine the circumstances under which the presumption could be rebutted. RPGI asks the Commission to grant rehearing to reject the use of ranges of presumptively just and reasonable ROEs.[320]

C. Commission Determination

190. We grant rehearing and hold that the ranges of presumptively just and reasonable base ROEs will be calculated by dividing the overall composite zone of reasonableness into three equal portions. We are persuaded by the requests for rehearing that contend that the Commission's ranges of presumptively just and reasonable base ROEs should encompass the entire composite zone of reasonableness. The court in *Emera Maine* stated that "the zone of reasonableness creates a broad range of potentially lawful ROEs[,]"[321] and we now find that excluding the bottom eighth and top eighth of the overall zone of reasonableness, as the Commission's approach in Opinion No. 569 did, is inappropriate because it will ignore some "potentially lawful ROEs" when determining which ranges of ROEs should be considered presumptively just and reasonable. The ranges of presumptively just and reasonable base ROEs are intended to help inform the Commission's analysis under section 206 by identifying what subset of the "potentially lawful ROEs" for given utilities represents the range of base ROEs that would likely be just and reasonable for utilities of that risk profile. We find that it would be inappropriate to identify a subset of "potentially lawful ROEs" for given utilities without considering all of those potentially lawful ROEs.

191. We are further persuaded by arguments that it is inappropriate to exclude the bottom eighth and top eighth of the overall composite zone of reasonableness because even those portions of the overall composite zone of reasonableness are results from proxy group companies that have been screened using criteria which limit the proxies to companies that are considered to present investment risks comparable to those of the utility or group of utilities whose rates are at issue. We find that, when we have already

[320] RPGI Rehearing Request at 9-16.

[321] *Emera Maine*, 854 F.3d at 26.

constructed a proxy group using limitations for comparable risk, it would be too restrictive to then construct ranges of presumptively just and reasonable base ROEs using only the results of some of those risk-screen proxy group companies. That initial proxy group screening process is intended to lead to the "broad range of potentially lawful ROEs" for a given utility or utilities, and we find that is more appropriate for the ranges of presumptively just and reasonable base ROEs to encompass the results from all of the proxy group companies that were identified in that process, rather than to exclude the results of the bottom eighth and top eighth of those results.

192. Exelon argues that the ranges of presumptively just and reasonable ROEs used in Opinion No. 569 are too narrow. MISO TOs make a similar argument, contending that the Commission's ranges of presumptively just and reasonable ROEs are inappropriate because they overlook that one or more proxies that fall within a particular risk profile range for one of the models used by the Commission may fall within a different risk profile range for a different model. CAPs make an opposing argument, asserting that the Commission's ranges are unnecessarily broad. We continue to find that using three risk groups strikes an appropriate balance between the interests of customers and utilities because they will be narrow enough to protect customers from unjust and unreasonable ROEs while also providing utilities and all market participants with an additional objective benchmark that the Commission will use to assess whether an ROE is likely unjust and unreasonable.[322] With respect to MISO TOs' argument that the ranges are inappropriate because the proxies that fall within a particular risk profile range for one of the models used by the Commission may fall within a different risk profile range for a different model, we find that this concern is addressed by averaging the results of the different models. We recognize that proxy group companies may fall within different risk profile ranges in different models, and this is why we average the results of those models. Indeed, this is a significant reason why we are considering different models and averaging their results—so that we can consider and give equal weight to the different results that are produced by these models, reflecting to a greater extent the models that investors consider.

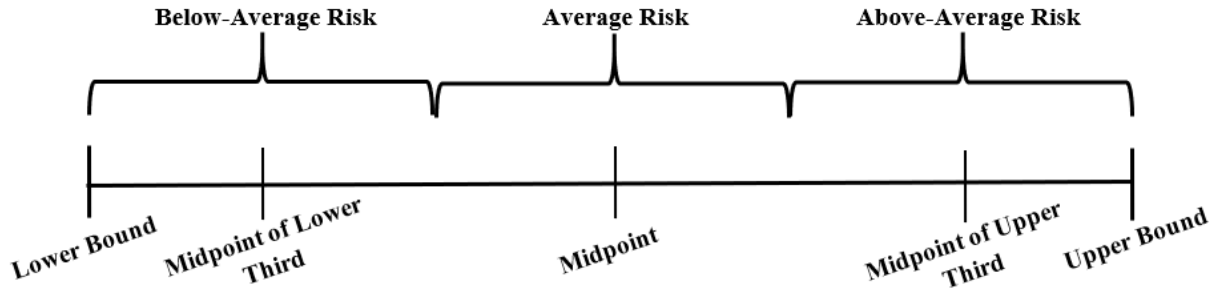
193. Accordingly, we will continue to use three ranges of presumptively just and reasonable base ROEs and that they should be constructed by dividing the overall zone of reasonableness into three equal segments. This construction will include all of the "potentially lawful ROEs" in the zone of reasonableness in one of the ranges of presumptively just and reasonable base ROEs.

194. The Commission explained that its approach to constructing the ranges of presumptively just and reasonable base ROEs in Opinion No. 569 was based on the logic that the end points of a range for a given risk profile should be closer to the traditional

[322] *See id.* P 84.

starting point for analyzing the ROEs of utilities with that risk profile than they are to the traditional starting points for utilities with a different risk profile.[323] Upon further consideration, given our decision to use three ranges of presumptively just and reasonable base ROEs that together encompass the overall zone of reasonableness, we find it appropriate to modify the traditional starting points for below-average and above-average risk utilities to be the midpoint of the lower and upper thirds, respectively. Applying these new starting points, as well as the traditional midpoint of the zone of reasonableness starting point for average risk utilities, will ensure that the end points for all three risk profile ranges will be closer to the starting point for analyzing ROEs of utilities with each respective risk profile than they are to the starting points for utilities with different risk profiles. Below is an illustration of the overall composite zone of reasonableness divided into three equal ranges of presumptively just and reasonable base ROEs.

Figure 2: Ranges of Presumptively Just and Reasonable Base ROEs



195. Exelon asserts that the use of ranges of presumptively just and reasonable base ROEs removes the burden on the complainant to demonstrate that an existing base ROE is unjust and unreasonable when such a base ROE is above the applicable range of presumptively just and reasonable ROEs because the utility or utilities then bear the burden of overcoming a presumption that its ROE is unjust and unreasonable. CAPs make a similar argument in the opposite direction, contending that the presumptively just and reasonable zones raise the customers' burden of proof to challenge ROEs that may have become unjust and unreasonable. We find these arguments unavailing. As the

[323] Opinion No. 569, 169 FERC ¶ 61,129 at P 63. Those traditional starting points were the midpoint of the zone of reasonableness for average risk utilities, the midpoint of the lower half of the zone for below-average risk utilities, and the midpoint of the upper half of the zone for above-average risk utilities.

Commission explained in Opinion No. 569,[324] the change to our ROE methodology to utilize ranges of presumptively just and reasonable ROEs does not change the burdens that parties face under section 206. It is merely an objective benchmark that will be used in our overall analysis of base ROEs to help determine if an existing rate has been shown to be unjust and unreasonable under section 206. It remains the case, as it was before implementing this modification to our ROE methodology, that "[t]he proponent of a rate change under section 206 . . . bears 'the burden of proving that the existing rate is *unlawful*.'"[325] The use of ranges of presumptively just and reasonable ROEs does not change this burden. Those ranges will merely serve to inform our assessment of ROEs. The fact that our use of those ranges will involve employing a rebuttable presumption does not change the burdens that apply.

196. MISO TOs and CAPs also take issue with the use of presumptively just and reasonable base ROEs because they assert that *Emera Maine* did not require the Commission to adopt the use of such ranges. As the Commission explained in Opinion No. 569,[326] the use of ranges of presumptively just and reasonable ROEs in our ROE methodology ensures that our determinations satisfy the requirements of the *Emera Maine* decision. The court in *Emera Maine* found that the Commission must "explain what circumstances" support its "actual finding as to the lawfulness" of an existing base ROE in a section 206 proceeding, and the use of ranges of presumptively just and reasonable base ROEs will allow us to do so in a structured manner. Using such ranges will produce a specific result from our risk profile determination—a rebuttable presumption—and then we will make an explicit finding as to whether the other evidence presented by the parties in the case has rebutted that presumption; therefore, this analysis will require us to "explain what circumstances" support our "actual finding as to the lawfulness" of an existing base ROE. Moreover, because risk profile is the particular circumstance most relevant to determining whether an existing ROE is unjust and unreasonable, using ranges of presumptively just and reasonable ROEs based on a utility's risk profile will ensure that the risk profile determination has a clear and significant connection to our ultimate finding relating to lawfulness. Accordingly, we continue to find that that the use of ranges of presumptively just and reasonable ROEs in our ROE methodology will ensure that our determinations satisfy the requirements of the *Emera Maine* decision.

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[324] *See id.* P 79.

[325] *Emera Maine*, 854 F.3d at 24 (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)).

[326] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 70-71.

197. CAPs and RPGI assert that the use of ranges of presumptively just and reasonable base ROEs is inappropriate because any base ROE that exceeds the applicable base ROE produced by the Commission's analyses should be found unjust and unreasonable. We disagree. As the Commission stated in Opinion No. 569,[327] the court in *Emera Maine* rejected this approach, finding that the Commission must do more than simply identify a single ROE from its own analysis and then determine if the existing ROE is unjust and unreasonable based on whether it exceeds that single ROE. Accordingly, we affirm the Commission's finding that it should not continue to follow the approach that was reversed in *Emera Maine* of identifying a single cost of equity result and then finding that an existing ROE is unjust and unreasonable under prong one of section 206 if it exceeds that cost of equity.

198. CAPs also reiterate their argument that the use of ranges of presumptively just and reasonable base ROEs creates an unlawful asymmetry between rate increases sought by utilities under section 205 and rate reductions sought by customers under section 206. We disagree and affirm the Commission's finding that the use of presumptively just and reasonable ranges does not create any such unlawful asymmetry.[328] As the Commission explained, the showing that is required under section 206 differs from the showing that is required under section 205. The D.C. Circuit explained that "[t]he purpose of section 206 is 'quite different' from that of section 205,"[329] "[s]ection 206's procedures are 'entirely different' and 'stricter' than those of section 205," and that, while "[a] utility filing a rate adjustment under section 205 must show that the adjustment is *lawful* . . . [t]he proponent of a rate change under section 206 [] bears 'the burden of proving that the existing rate is *unlawful*.'"[330] The Commission does not have the authority to change those standards and our modification of the Commission's ROE methodology to use ranges of presumptively just and reasonable ROEs adheres to those standards; therefore, we reject CAPs' argument on this point.

199. We also are not persuaded by CAPs' argument that the use of ranges of presumptively just and reasonable base ROEs is inconsistent with other rulings made by the court in *Emera Maine*. Contrary to CAPs' assertion, the use of such ranges does not assume that there are only three possible stopping points—lower midpoint, midpoint, and upper midpoint—on the continuum of "potentially just and reasonable" ROEs. In fact, it

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[327] *See id.* P 73.

[328] *See id.* P 74.

[329] *Emera Maine*, 854 F.3d at 24 (quoting *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875 (D.C. Cir. 1984)).

[330] *Id.* (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)).

does the opposite—it recognizes that there may be more than one just and reasonable return and employs ranges of just and reasonable ROEs to help determine if a particular existing base ROE is just and reasonable in light of the overall composite zone of reasonableness and the risk profile of the utilities at issue. The use of presumptively just and reasonable ranges also does not find that if a rate falls within the zone of reasonableness, then it is just and reasonable, as CAPs suggest. As described above, the fact that a rate falls within the zone of reasonableness will not result in a finding that such a rate is just and reasonable. In fact, it is possible that a rate that falls within the overall zone, but outside of the applicable presumptively just and reasonable range, would be presumed unjust and unreasonable. Similarly, whether an existing ROE is unjust and unreasonable, even one that falls within the applicable range of presumptively just and reasonable ROEs, still "depends on the particular circumstances of the case."[331] Accordingly, if an existing ROE falls within the applicable range of presumptively just and reasonable ROEs, the presumption that the ROE is just and reasonable is a rebuttable presumption. Therefore, other evidence regarding the particular circumstances of the case can demonstrate that an existing ROE is unjust and unreasonable even if it falls within the applicable range of presumptively just and reasonable ROEs, such as evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, and testimony regarding the effects of rates on customers.

XV. Acting in these Proceedings as Opposed to in Base ROE NOI Proceeding

A. Rehearing Requests

200. Parties on rehearing argue that, because the Commission has sought public input on the Commission's base ROE policy from all interested parties in the Base ROE NOI proceeding,[332] it would be inappropriate for the Commission to establish a new base ROE policy in these MISO ROE proceedings without considering the broader universe of comments and evidence submitted in response to the Base ROE NOI.

201. Specifically, Exelon states that the thousands of pages of comments from utilities, industry groups, and other interested parties provided the Commission with a wide range of perspectives and valuable data. Exelon, MISO TOs, and Ameren argue that promulgating a new ROE method in an individual proceeding ignores the evidence submitted in the Base ROE NOI docket.[333] Moreover, Exelon, Transource Energy, and

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[331] *Id.*

[332] Base ROE NOI, 166 FERC ¶ 61,207.

[333] Exelon Rehearing Request at 27; *see also* MISO TOs Rehearing Request at 56-57; Ameren Rehearing Request at 27.

Ameren explain that, in the Base ROE NOI proceeding, the Commission specifically sought comments regarding the ROE four-financial model approach and, therefore, those parties participating in the Base ROE NOI proceeding did not address the new ROE two-model method that was introduced in Opinion No. 569 or the potential issues with the ROE four-model financial model approach revealed in Opinion No. 569.[334] Exelon and Ameren comment that establishing a new base ROE policy in these proceedings, as opposed to the Base ROE NOI proceeding, is inappropriate because the Commission's actions here will not reflect the input and evidence that was provided in the Base ROE NOI proceeding by other stakeholders who are not parties to these proceedings.[335] Exelon argues that the Commission should not rely on the fact that an outcome is reasonable as applied to this group of transmission owners, without analyzing the potential outcomes that will result from wider application of this method.[336] Transource Energy recognizes that the Commission has some discretion to enact policies through adjudication. However, it contends that under this set of circumstances the Commission's reliance on an adjudication and not the pending Base Roe NOI "amounts[s] to an abuse of discretion" that violates the Administrative Procedure Act.[337]

202. MISO TOs also assert that the Commission does not engage in reasoned decision-making when it disregards relevant evidence available to it, even if the evidence is in a different docket,[338] and it would be arbitrary and capricious for the Commission to set an industry-wide, binding precedent while ignoring this evidence.[339] Accordingly, MISO TOs argue that the Commission should take official notice in this proceeding of pertinent evidence introduced in the NOI docket.[340] MISO TOs state that the Commission's generic, industry-wide NOI on the methodology for determining base ROEs provides a more logical and reasonable forum for the Commission to develop, with

[334] Exelon Rehearing Request at 27-28; Transource Energy Rehearing Request at 36-37; Ameren Rehearing Request at 24.

[335] Exelon Rehearing Request at 5, 12, 27; Ameren Rehearing Request at 24.

[336] Exelon Rehearing Request at 27.

[337] Transource Energy Rehearing Request at 37 (quoting *NLRB v. Bell Aerospace Co.*, 416 U.S. 267, 294 (1974)).

[338] MISO TOs Rehearing Request at 55.

[339] *Id.* at 58.

[340] *Id.* at 55.

the benefit of the extensive stakeholder input it solicited, any changes to its ROE methodology that it may find to be appropriate.[341]

203. Ameren argues that the fact that the Commission has left open the generic NOI docket, while at the same time making an industry-wide policy change in this adjudicated proceeding, constitutes arbitrary and capricious agency decision-making.[342]

204. Finally, Exelon asserts that the Commission should limit the application of any new method for assessing base ROEs adopted by Opinion No. 569 to these MISO cases and clarify that the Commission is not prejudging the application of any new method to other utilities.[343]

B. Commission Determination

205. We are not persuaded that it is inappropriate for the Commission to establish a new base ROE policy in these MISO complaint proceedings when it has also issued the Base ROE NOI to obtain input on this topic from interested parties. The Commission "has substantial discretion to establish rules of general application by case-specific adjudication and is not restricted to the use of a separate generic proceeding"[344] to

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[341] *Id*. at 37.

[342] Ameren Rehearing Request at 24.

[343] Exelon Rehearing Request at 28.

[344] Opinion No. 569, 169 FERC ¶ 61,129 at P 449 (quoting *Procedures for Disposition of Contested Audit*, Order No. 675, 114 FERC ¶ 61,178, at P 32 (2006). *See also NLRB v. Bell Aerospace Corp*., 416 U.S. 267, 294 (1974) ("[A]djudicative cases may and do serve as vehicles for the formulation of agency policies."); *SEC v. Chenery Corp*., 332 U.S. 194, 203 (1974) ("[T]he choice made between proceeding by general rule or by individual, ad hoc litigation is one that lies primarily in the informed discretion of the administrative agency."); *Michigan-Wisconsin Pipeline Co. v. FPC*, 520 F.2d 84, 89 (D.C. Cir. 1975) ("[T]here is no question that the Commission may attach precedential and even controlling weight to principles developed in one proceeding and then apply them under appropriate circumstances in a stare decisis manner."); *Pac. Gas and Electric Co. v. FPC*, 506 F.2d. 33, 38 (D.C. Cir. 1974) ("[A]gency may establish binding policy through rulemaking procedures . . . or through adjudications which constitute binding precedents."); *AEP Power Mktg., Inc*., 108 FERC ¶ 61,026, at P 187 (2004) ("Our decision to establish new policy in the context of case-specific proceedings is clearly within our authority."); *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 103 FERC ¶ 61,349, at P 51 (2003) ("The Commission, moreover, is not limited to notice and comment rulemaking to develop

establish such rules. The Commission similarly has explained that "[o]ur decision to establish new policy in the context of case-specific proceedings is clearly within our authority."[345] Thus, while the Commission issued the Base ROE NOI, this did not prohibit it from changing its base ROE policy in an adjudication nor require that changes in base ROE policy occur in that Base ROE NOI proceeding. Importantly, we note that the due process protections afforded to all parties to these proceedings are available to every party to Commission proceedings. Any party in other proceedings will be free to argue, just as the parties to these proceedings were, that the base ROE methodology applied in any of these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that party.

XVI. Complaint-Specific Results: First Complaint

206. As discussed in this order, we are revising the methodology for determining whether an existing ROE is unjust and unreasonable and, if so, what is a just and reasonable ROE pursuant to section 206 of the FPA. Applying this methodology to the First Complaint proceeding, we continue to find that the rate to be reviewed in that proceeding— MISO TOs' 12.38% ROE—is unjust and unreasonable. Having addressed the first prong of the Commission's dual burden under section 206 and thus satisfied the "condition precedent"[346] to exercising our authority to change a rate under section 206, we grant rehearing of Opinion No. 569 and find that a just and reasonable replacement ROE for MISO TOs in the First Complaint proceeding is 10.02% under the second prong of section 206.

207. Below we address the "specific findings"[347] as to the "'particular circumstances'"[348] of the First Complaint proceeding that establish "'a rational connection'"[349] between the record evidence in that proceeding and our decisions under both prongs of section 206 herein to establish that we have "'made a principled and

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policy. Agencies generally are permitted considerable discretion to choose whether to proceed by rulemaking or by adjudication.")).

[345] *AEP Power Mktg.*, 107 FERC ¶ 61,018, at P 199 (2004).

[346] *Emera Maine*, 854 F.3d at 25 (citing *FPC v. Sierra Pac. Power*, 350 U.S. 348, 353 (1956)).

[347] *Id.* at 30.

[348] *Id.* at 27 (citing *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

[349] *Id.* at 28 (citing *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 782 (2016)).

reasoned decision supported by the evidentiary record.'"[350] The Commission bases its decisions concerning just and reasonable ROEs for public utilities on the most recent information in the record regarding market cost of equity. Consequently, the starting point for determining whether MISO TOs' existing ROE has become unjust and unreasonable must be a consideration of whether the current market cost of equity has changed since the MISO TOs' existing ROE was established based on financial data for the six months ending February 2002, such that the existing base ROE is no longer just and reasonable. Accordingly, we begin by determining a composite zone of reasonableness using the most recent financial information in the record of the First Complaint proceeding. We continue to find that the appropriate study period including this most recent financial information is the first six months of 2015.[351]

A. DCF Analysis

208. In Opinion No. 569, the Commission affirmed Opinion No. 551's approval of the Presiding Judge's DCF analysis, with one exception. In Opinion No. 569, the Commission held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate including both short- and long-term growth rates that was used by the Presiding Judge. Here, we affirm the Commission's holding on that issue and the Commission's use of the low-end outlier test applied in Opinion No. 569. Accordingly, our determinations on those issues do not result in any changes to the DCF analysis that was used in Opinion No. 569 for the First Complaint proceeding.

209. As discussed above, we grant rehearing of Opinion No. 569 to modify the high-end outlier test that was used there to now treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. The Commission explained in Opinion No. 569 that applying the version of the high-end outlier test that was used there did not result in the exclusion of any company from the DCF proxy group as a high-end outlier.[352] The high-end outlier test as modified in this order also does not result in any exclusions. Accordingly, our determination on this issue also does not result in any changes to the DCF analysis that was used in Opinion No. 569. We also grant rehearing of Opinion No. 569 to find that the long-term growth rate should be given 20% weighting and the short-term growth rate 80% weighting in the two-step

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[350] *Id.* at 30 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 181).

[351] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 460; Opinion No. 551, 156 FERC ¶ 61,234 P 19.

[352] Opinion No. 569, 169 FERC ¶ 61,129 at P 512.

DCF model. Our DCF analysis in the First Complaint proceeding reflecting this finding is shown in Appendix II to this order. Based on these determinations, we conclude that the DCF zone of reasonableness is 6.97% to 12.07%.

B. CAPM Analysis

210. In Opinion No. 569, the Commission affirmed Opinion No. 551's approval of the Presiding Judge's CAPM analysis in the First Complaint proceeding, with two exceptions related to the market risk premium. The Commission held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, instead of the average of the IBES and *Value Line* growth projections approved by the Presiding Judge.[353] In addition, the Commission held that companies with negative ROEs or ROEs above 20% should be excluded from that analysis.[354]

211. As discussed above in section IV.C.1, we grant rehearing of Opinion No. 569 to, in future proceedings, consider the use of *Value Line* short-term growth rate projections in the one-step DCF analysis of the dividend paying members of the S&P 500 that is conducted in the CAPM. However, we find that the record is insufficient to allow us to use only *Value Line* short-term growth rates in the CAPM in the First Complaint proceeding. In addition, we affirm the Commission's application of the low-end outlier test and grant rehearing to modify the high-end outlier test, as described above. As the Commission explained in Opinion No. 569, the application of the low-end outlier test and the version of the high-end outlier that was used there did not result in the exclusion of any company from the CAPM proxy group.[355] The low-end outlier test and the modified high-end outlier test adopted herein also do not result in the exclusion of any company from the CAPM proxy group. Accordingly, we will continue to use the CAPM analysis that was relied upon in Opinion No. 569 for the First Complaint proceeding.[356] Based on these determinations, we conclude that the CAPM zone of reasonableness is 7.80% to 13.09%.

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[353] Opinion No. 551, 156 FERC ¶ 61,234 at PP 169, 172.

[354] Opinion No. 569, 169 FERC ¶ 61,129 at P 513.

[355] *See id.* PP 514-515.

[356] *See id.* P 513. The results of this CAPM analysis are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

C. Risk Premium Analysis

212. As discussed above, we grant rehearing of Opinion No. 569 to find that the Risk Premium Model should be used in our ROE analysis under section 206 of the FPA. As described above, we adopt modifications to the Risk Premium analysis that was provided by MISO TOs in the record for the First Complaint proceeding. Appendix I to this order shows the results of the Risk Premium Model, as applied with modifications adopted herein.

213. This Risk Premium Model produces an ROE result of 10.10%.[357] As further discussed above, we will impute a zone of reasonableness from the ROE produced by the Risk Premium model for purposes of using the Risk Premium model in our analysis under the first prong of section 206. We do so by applying the average of the widths of the zones of reasonableness from the CAPM and DCF models to the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. In the First Complaint proceeding, the result of the Risk Premium Model is 10.10% and the average width of the zones of reasonableness produced by the CAPM and DCF models is 520 basis points. Applying this value to the Risk Premium result to impute a zone of reasonableness results in a Risk Premium zone of reasonableness of 7.50% to 12.70%.[358]

D. Composite Zone of Reasonableness and Section 206 Findings

214. Averaging the top and bottom of the DCF, CAPM, and Risk Premium zones of reasonableness determined above based on financial data for the first six months of 2015 produces a composite zone of reasonableness in the First Complaint proceeding of 7.42% to 12.62%. The midpoint of that zone of reasonableness is 10.02%.

215. Having determined the composite zone of reasonableness based on financial data for the first half of 2015, we now turn to considering whether the MISO TOs' 12.38% ROE, which was determined based on financial data for the six months ending February 2002, may be found unjust and unreasonable pursuant to the first prong of section 206. In this order, we affirm the Commission's decision in Opinion No. 569 to use ranges of presumptively just and reasonable ROEs based on the risk profile of the MISO TOs to inform our decision whether their ROE has become unjust and unreasonable. However, as discussed above, we grant rehearing of Opinion No. 569 to find that those ranges should be calculated by dividing the overall composite zone of reasonableness into equal thirds.

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[357] *See* Appendix I.

[358] *Id.*

216. We affirm the Commission's determination in Opinion No. 569 that the MISO TOs should be treated as of average risk for purposes of determining the range of presumptively just and reasonable ROEs applicable to the MISO TOs.[359] In light of this determination, we find that the range of presumptively reasonable ROEs for consideration in determining whether MISO TOs' base ROE of 12.38% ROE in the First Complaint proceeding is unjust and unreasonable should be the middle third of the zone of reasonableness based on the revised construction of the presumptively just and reasonable zones adopted in this order. In the First Complaint proceeding, that range is from 9.15% to 10.89%.[360]

217. The MISO TOs' 12.38% is 149 basis points above the range of presumptively just and reasonable ROEs for the MISO TOs. Accordingly, we find that it is presumptively unjust and unreasonable. It is thus clear that, in light of our estimate of the cost of capital, the MISO TOs' 12.38% ROE is well outside any possible range of potentially just and reasonable ROEs for the MISO TOs. In order to rebut the presumption that the ROE is unjust and unreasonable, we would look at other evidence, such as state ROEs, ROEs of non-utility companies, ROEs produced by other methodologies, non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, or testimony regarding the effects of rates on customers that would indicate that this is not the case. However, the record lacks such evidence sufficient to rebut the presumption. For example, the evidence in the record regarding state ROEs indicates that all state-authorized ROEs during the period April 1, 2013 through March 31, 2015 for integrated electric utilities providing generation, transmission, and distribution services ranged from 9.5% to 10.4% and that 87.34% of state-authorized ROEs for both integrated electric utilities and distribution-only electric utilities during that period were within this range.[361] The fact that MISO TOs' 12.38% ROE is 198 basis points above this range further demonstrates that MISO TOs' 12.38% ROE is unjust and unreasonable. In these circumstances, we find under the first prong of section 206 that the MISO TOs' 12.38% ROE that is the subject of the First Complaint proceeding has become unjust and unreasonable.

218. Having found that the MISO TOs' existing ROE is unjust and unreasonable, we turn to the establishment of a just and reasonable replacement ROE under the second prong of section 206. As discussed above, we have found that the midpoint of the composite zone of reasonable ROEs based on the most recent financial information in the record of the First Complaint proceeding is 10.02%. As discussed above, we find that the

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[359] *See id.* PP 518-521.

[360] *See* Appendix III.

[361] *See, e.g.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 240.

MISO TOs are of average risk. Our policy is to set an RTO-wide ROE at the midpoint of the zone of reasonableness when the transmission owners receiving the RTO-wide ROE are of average risk. Accordingly, we find that the just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 10.02%. We therefore grant rehearing of Opinion No. 569 in part to require the MISO TOs to adopt a 10.02% ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32% ROE.

XVII. Complaint Specific Results: Second Complaint

A. Existing Rate for Purposes of Second Complaint and Overview

219. As discussed further below, we affirm the Commission's finding in Opinion No. 569 that the 10.02% base ROE established in the First Complaint proceeding is the existing rate to be reviewed for purposes of the Second Complaint proceeding because that is the rate which we would have to find unjust and unreasonable under the first prong of section 206 of the FPA, before we could require a new ROE "to be thereafter observed" pursuant to the second prong of section 206. As the Commission explained in Opinion No. 569, any new just and reasonable rate that we require "to be thereafter observed" pursuant to section 206(a) will replace the currently effective rate, not some previously effective rate. Accordingly, in order to determine a new rate to be thereafter observed, we must examine what the currently effective rate is because that is the rate that will need to be replaced if it is unjust and unreasonable. As discussed in the preceding section, in the First Complaint proceeding, we require MISO TOs to reduce their ROE to 10.02% effective prospectively from September 28, 2016. Therefore, that is the MISO TOs' currently effective ROE when we are deciding whether MISO TOs' ROE is unjust and unreasonable and should be modified prospectively pursuant to section 206 in the Second Complaint proceeding.

220. As discussed in this order, we are revising the methodology for determining whether an existing ROE is unjust and unreasonable and, if so, what is a just and reasonable ROE pursuant to section 206. Applying this methodology to the Second Complaint proceeding, we continue to find that the rate to be reviewed in that proceeding— 10.02% base ROE established in the First Complaint proceeding—has not been shown to be unjust and unreasonable.

221. Below we address the "specific findings"[362] as to the "'particular circumstances'"[363] of the Second Complaint proceeding that establish "'a rational

[362] *Emera Maine*, 854 F.3d at 30.

[363] *Id.* at 27 (citing *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

connection'"[364] between the record evidence in that proceeding and our decisions under both prongs of section 206 herein to establish that we have "'made a principled and reasoned decision supported by the evidentiary record.'"[365] Because the Commission bases its decisions concerning just and reasonable ROEs for public utilities on the most recent information in the record regarding market cost of equity, the starting point for determining whether the MISO TOs' existing ROE has become unjust and unreasonable must be a consideration of whether the current market cost of equity has changed such that the 10.02% base ROE established in the First Complaint proceeding is unjust and unreasonable. Accordingly, we begin by determining a composite zone of reasonableness using the most recent financial information in the record of the Second Complaint proceeding. We continue to find that the appropriate study period including this most recent financial information is July 1, 2015 through December 31, 2015.[366]

B. DCF Analysis

222. In Opinion No. 569, the Commission affirmed the Presiding Judge's DCF analysis in Initial Decision (II) with one exception. The Commission held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate including both short- and long-term growth rates that was used by the Presiding Judge. Here, we affirm the Commission's holding on that issue and the Commission's use of the low-end outlier test applied in Opinion No. 569. Accordingly, our determinations on those issues do not result in any changes to the DCF analysis that was used in Opinion No. 569 for the Second Complaint proceeding.

223. As discussed above, we grant rehearing of Opinion No. 569 to modify the high-end outlier test that was used there. The Commission explained in Opinion No. 569 that applying the version of the high-end outlier test that was used there did not result in the exclusion of any company from the DCF proxy group as a high-end outlier.[367] The high-end outlier test as modified in this order also does not result in any exclusions. Accordingly, our determination on this issue also does not result in any changes to the DCF analysis that was used in Opinion No. 569. We also grant rehearing of Opinion No. 569 to find that the long-term growth rate should be given 20% weighting and the short-term growth rate 80% weighting in the two-step DCF model. Our DCF analysis in the Second Complaint proceeding reflecting this finding is shown in Appendix II to this

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[364] *Id.* at 28 (citing *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 782 (2016)).

[365] *Id.* at 30 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 181).

[366] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 524.

[367] *Id.* P 554.

order. Based on these determinations, we conclude that the DCF zone of reasonableness is 7.37% to 11.37%.

C. CAPM Analysis

224. In Opinion No. 569, the Commission affirmed the Presiding Judge's CAPM analysis in the Second Complaint proceeding, with one exception related to the market risk premium. The Commission held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, which was consistent with the Presiding Judge's approach in Initial Decision (II).[368] In addition, the Commission held that companies with negative ROEs or ROEs above 20% should be excluded from that analysis.[369]

225. As discussed above in section IV.C.1, we grant rehearing of Opinion No. 569 to, in future proceedings, consider the use of *Value Line* short-term growth rate projections in the one-step DCF analysis of the dividend paying members of the S&P 500 that is conducted in the CAPM. However, we find that the record is insufficient to allow us to use only *Value Line* short-term growth rates in the CAPM in the Second Complaint proceeding. In addition, we affirm the Commission's application of the low-end outlier test and grant rehearing to modify the high-end outlier test as described above. As the Commission explained in Opinion No. 569, the application of the low-end outlier test and the version of the high-end outlier test that was used there did not result in the exclusion of any company from the CAPM proxy group.[370] The low-end outlier test and modified high-end outlier test adopted herein also do not result in the exclusion of any company from the CAPM proxy group. Accordingly, we will continue to use the CAPM analysis that was relied upon in Opinion No. 569 for the Second Complaint proceeding.[371] Based on these determinations, we conclude that the CAPM zone of reasonableness is 8.35% to 12.63%.

D. Risk Premium Analysis

226. As discussed above, we grant rehearing of Opinion No. 569 to find that the Risk Premium Model should be used in our ROE analysis under section 206 of the FPA. As

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[368] *See* Initial Decision (II), 155 FERC ¶ 63,030 at P 412.

[369] Opinion No. 569, 169 FERC ¶ 61,129 at P 555.

[370] *See id.* PP 556-557.

[371] *See id.* P 513. The results of this CAPM analysis are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

described above, we are adopting modifications to the Risk Premium analysis that was provided by the MISO TOs in the record for the Second Complaint proceeding. Appendix I of this order shows the results of the Risk Premium Model, as applied with modifications adopted herein.

227. This Risk Premium analysis produces an ROE result of 10.29%.[372] As further discussed above, we find that we will impute a zone of reasonableness from the ROE produced by the Risk Premium model for purposes of using the Risk Premium model in our analysis under the first prong of section 206. We do so by applying the average of the widths of the zones of reasonableness from the CAPM and DCF models to the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. In the Second Complaint proceeding, the result of the Risk Premium analysis is 10.29% and the average width of the zones of reasonableness produced by the CAPM and DCF models is 414 basis points. Applying this value to the Risk Premium result to impute a zone of reasonableness results in a Risk Premium zone of reasonableness of 8.22% to 12.36%.[373]

E. Composite Zone of Reasonableness and Section 206 Findings

228. Averaging the top and bottom of the DCF, CAPM, and Risk Premium zones of reasonableness determined above based on the most recent financial data in the record of the Second Complaint proceeding produces a composite zone of reasonableness in the Second Complaint proceeding of 7.98% to 12.12%. The midpoint of that zone of reasonableness is 10.05%.

229. The applicable range of presumptively just and reasonable ROEs for the MISO TOs in the Second Complaint proceeding is from 9.36% to 10.74%. As discussed above, the issue to be addressed in the Second Complaint is whether the ROE established in the First Complaint remains just and reasonable during the applicable test period as addressed by the evidence presented by the participants in the Second Complaint. The MISO TOs' 10.02% ROE established upon resolution of the First Complaint proceeding falls within the range of presumptively just and reasonable ROEs that applies in the Second Complaint. We find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. We see no evidence in the record, such as state ROEs, ROEs of non-utility companies, and other methodologies that rebuts this presumption. Accordingly, we do not find that the MISO TOs' ROE established in the First Complaint proceeding and in effect as of the date of this order is unjust and unreasonable under the first prong of section 206. For that reason, we do not establish a

[372] *See* Appendix I.

[373] *Id.*

new just and reasonable ROE in the Second Complaint proceeding to be in effect prospectively from the date of this order.

XVIII. Refund Issues

A. Opinion No. 569

230. In Opinion No. 569, the Commission granted rehearing of Opinion No. 551 in part, found that the challenged 12.38% base ROE in the First Complaint proceeding was unjust and unreasonable, and additionally found that a replacement base ROE of 9.88% was just and reasonable—instead of the 10.32% replacement ROE that was set in Opinion No. 551. The Commission made the 9.88% ROE effective as of September 28, 2016, the date on which Opinion No. 551 was issued.[374] The Commission ordered MISO and the MISO TOs to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a, for the 15-month refund period for the First Complaint proceeding from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016—the date on which Opinion No. 551 was issued—to the date of Opinion No. 569.[375]

231. The Commission then found that the 9.88% base ROE established in the First Complaint proceeding was the existing rate to be analyzed for purposes of the Second Complaint proceeding. In brief, the Commission reasoned that, for purposes of deciding whether a rate charged by a utility is unjust and unreasonable and determining a new just and reasonable rate "to be thereafter observed" pursuant to section 206(a) of the FPA, it must assess whether the public utility's currently effective rate is unjust and unreasonable, not some earlier rate that may have been in effect when the complaint was filed but has now been superseded. The Commission explained that, in other words, in order to determine a new rate to be thereafter observed, it must examine the currently effective rate because that is the rate that will need to be replaced if it is unjust and unreasonable. The Commission then explained that, because the 9.88% base ROE established in the First Complaint proceeding is effective prospectively from September 28, 2016, that is the currently effective rate that the Commission would have to find unjust and unreasonable under the first prong of section 206, before we could require a new ROE "to be thereafter observed" pursuant to the second prong of section 206.[376]

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[374] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 20.

[375] *Id.* at ordering para. (B).

[376] *Id.* P 530.

232. The Commission then concluded that the 9.88% ROE was just and reasonable based on the facts and circumstances of the Second Complaint and therefore dismissed the Second Complaint. The Commission then found that section 206 dictates that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding (i.e., the Commission sets a new just and reasonable rate which it "orders to be thereafter observed and in force.").[377] The Commission concluded that it could not order refunds for the Second Complaint proceeding's refund period because it was dismissing the complaint and not granting any prospective relief. The Commission found that ordering refunds in the Second Complaint proceeding despite the fact that it was granting no prospective relief would exceed the statutory authority in section 206 because it would effectively extend the 15-month refund period for the First Complaint since the refunds would be based on the relief granted in the First Complaint and not any action taken in the Second Complaint.

B. First Complaint Proceeding Refunds

1. Rehearing Requests

233. MISO TOs argue that the Commission erred in directing refunds for the period from September 28, 2016, through the date of Opinion No. 569 based on the new ROE set in the First Complaint proceeding. MISO TOs contend that the effective date of the new base ROE resulting from resolution of the First Complaint proceeding should be November 21, 2019, the date on which Opinion No. 569 was issued. MISO TOs acknowledge that, in cases of legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made, but they assert that this is not a case of legal error because Opinion No. 569's adoption of a new ROE methodology goes beyond what is necessary to fix the problems identified by the *Emera Maine* court. MISO TOs contend that the court merely found that the Commission never explained how its ultimate placement of the base ROE was just and reasonable and that the Commission could correct this error by better tying the 10.32% base ROE set in Opinion No. 551 to the evidence in the record, rather than adopting a new base ROE methodology.[378] MISO TOs maintain that, therefore, the Commission's adoption of the 9.88% ROE for the First Complaint proceeding in Opinion No. 569 does not remedy a legal error.[379]

234. MISO TOs further argue that this is also not a case where the Commission fixed an error on rehearing of Opinion No. 551. They contend that, while the Commission

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[377] *Id.* P 568.

[378] MISO TOs Rehearing Request at 84-85 (citing *Emera Maine*, 854 F.3d at 28).

[379] *Id.*

"grant[ed] rehearing of Opinion No. 551 in part to require the MISO TOs to adopt a 9.88% ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32% ROE,"[380] it is unclear as to which issue presented on rehearing the Commission actually granted. MISO TOs assert that none of the rehearing requests asked the Commission to adopt a new ROE methodology, and instead opposing parties requested rehearing on the grounds that the composition of the DCF proxy group was incorrect, and that Commission should consider only DCF results, ignore the anomalous capital market conditions that impacted the DCF model inputs, and ignore cost of equity evidence produced by alternative models.[381]

235. MISO TOs argue that, therefore, in establishing the new 9.88% base ROE upon resolution of the First Complaint proceeding, the Commission was acting on its own motion pursuant to its authority under section 313(a) of the FPA[382] to modify Opinion No. 551. They contend that, as a result, the 9.88% base ROE that the Commission established upon resolution of the First Complaint proceeding can be effective only prospectively as of the date of the issuance of Opinion No. 569—November 21, 2019.[383]

236. MISO TOs argue that, if the Commission holds that it did fix a legal error through the adoption of the new methodology for determining a base ROE, the Commission should nonetheless use its discretion not to require the payment of interest on the refunds directed. MISO TOs note that "the Commission is not required to order that interest be paid on all refunds"[384] and contend that the Commission should use its discretion not to include interest with the refunds for the period from September 28, 2016, going forward because the full status quo ante cannot be restored in this case. They assert that this is the case because the Commission has implicitly recognized that some non-public utility members of MISO do not have a refund obligation relating to complaints that were filed prior to 2017,[385] and thus that non-public utility members of MISO may not have an obligation to make refunds for the First Complaint, which was filed in 2013. MISO TOs

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[380] *Id.* at 85-86 (citing Opinion No. 569, 169 FERC ¶ 61,129 at PP 20, 523).

[381] *Id.* at 86.

[382] *Id.* (citing 16 U.S.C. § 825l(a) (2018)).

[383] *Id.* at 86-87.

[384] *Id.* at 87 (citing *Trunkline Gas Co.*, 69 FERC ¶ 61,047, at 61,183 (1994) (citing *Estate of French v. FERC*, 603 F.2d 1158, at 1167–68 (5th Cir. 1979))).

[385] *Id.* at 88-89 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,050, at P 24 (2015) (only as of the effective date of their RTO adder are non-public utilities obligated to make refunds for Docket Nos. EL14-12 and EL15-45)).

argue that, without all transmission-owning members of MISO contributing their share of refunds, it will be impossible to reinstitute the full status quo ante.[386]

237. Ameren similarly argues that the 9.88% base ROE that the Commission found to be a new just and reasonable base ROE in the First Complaint proceeding cannot be made effective as of the date of Opinion No. 551, and thus no refunds can be directed for the period from September 28, 2016 to November 21, 2019. Ameren contends that section 206 of the FPA only permits the Commission to make a new just and reasonable rate effective prospectively and that, therefore, the Commission acted beyond its authority in making the 9.88% base ROE established in Opinion No. 569 effective as of the date of Opinion No. 551.[387]

238. Ameren asserts that the D.C. Circuit's decision in *City of Anaheim v. FERC* also prohibits the Commission from requiring refunds for the period from September 28, 2016 to November 21, 2019, based on its finding in the First Complaint proceeding that 9.88% is a new just and reasonable base ROE. Ameren contends that, in that case the Commission granted a complaint, but stated that it would set a just and reasonable rate in the future, and the court found that the Commission could not make the rate that it set in the future effective retroactively. Ameren argues that there is no meaningful difference between postponing the fixing of a new rate as the Commission did in *City of Anaheim* and modifying Opinion No. 551 and replacing the rate fixed there with another one calculated by a different method, as the Commission did in Opinion No. 569. Ameren contends that the act of fixing a new rate undersection 206 cannot be a three-year process because that would impermissibly expand the Commission's refund authority.[388]

239. Ameren argues that the legal error doctrine does not give the Commission authority to direct refunds for the period from September 28, 2016, to November 21, 2019, as a result of its decision in the First Complaint proceeding. Ameren asserts that, unlike the *ISO New England Inc. v. Bangor Hydro-Electric Co.*[389] case that the Commission cites in Opinion No. 569, a court has not vacated any of the Commission decisions in these proceedings and therefore the legal error doctrine does not apply in these proceedings. Ameren acknowledges that the Commission is empowered to change

[386] *Id.* at 89.

[387] Ameren Rehearing Request at 13-20.

[388] *Id.* at 17-19.

[389] 161 FERC ¶ 61,031 (2017).

its order on rehearing, but argues that, when doing so, it can only fix a new rate that is "thereafter observed."[390]

240. Transource Energy argues that the Commission can only make the rate that it adopts for the First Complaint proceeding effective prospectively, and not effective as of the date of Opinion No. 551.[391] Transource Energy asserts that, if the Commission believes it has the discretion to make the rate adopted upon resolution of the First Complaint proceeding effective as of the date of Opinion No. 551, it should find that the 10.32% ROE ordered in Opinion No. 551 is just and reasonable. Transource Energy further contends that under the Commission's methodology adopted in Opinion No. 569, there is no evidence showing that a 10.32% ROE is not just and reasonable. Transource Energy notes that the 10.32% base ROE adopted in Opinion No. 551 falls within the quartile range of presumptively just and reasonable ROEs for the period at issue in Opinion No. 551, which is 9.29% to 10.47%. Transource Energy further contends that the Commission's decision in Opinion No. 569 represents a change in policy and not a correction of a legal error. In addition, Transource Energy argues that the Commission should use its discretion to not order additional refunds for the First Complaint proceeding's 15-month refund period because customers benefitted from investments during the refund period.[392]

2. Commission Determination

241. We deny the requests for rehearing of the Commission's decision in Opinion No. 569 to order refunds for the period from September 28, 2016, to November 21, 2019, based on its decision in the First Complaint proceeding. In Opinion No. 569, the Commission granted rehearing of the Commission's decision in Opinion No. 551 that, in the First Complaint proceeding, a 10.32% base ROE was a just and reasonable new ROE under the second prong of section 206, instead finding that a 9.88% base ROE was a just and reasonable new ROE. Accordingly, the Commission's decision in Opinion No. 569 granted rehearing of the decision in Opinion No. 551 to make 10.32% the new base ROE effective prospectively from the date of Opinion No. 551. Consequently, the new ROE that the Commission set in Opinion No. 569 in granting rehearing, and which is modified in this order, is effective as of the date of the original decision which is being modified on rehearing (i.e., the date of Opinion No. 551).

242. As the Commission has explained, "[R]ate changes required in section 206 proceedings should take effect as of the date of the order setting rates, *not* the date of the

[390] Ameren Rehearing Request at 20-23.

[391] Transource Energy Rehearing Request at 36-38.

[392] *Id.*

rehearing—regardless of whether and to what extent the rehearing order changes the rates originally allowed."[393] The Commission further explained that "[s]uch a policy is fair to both utilities and ratepayers since it allows finally determined just and reasonable rates to go into effect at the earliest possible date, thereby preventing unjust enrichment of one party for any period of time. It also eliminates any incentive parties would have to delay the effective date of new rates."[394] Accordingly, the Commission's decision to grant rehearing of Opinion No. 551 to modify the rate established in that order for the First Complaint proceeding under section 206 takes effect as of the date of the order setting that rate (i.e., Opinion No. 551), not as of the date of Opinion No. 569 or this order. As discussed further below, because the changed rate set on rehearing of Opinion No. 551 is effective as of the date of that order, it is appropriate to direct refunds for the period from that date through the date of this order, which establishes the finally determined just and reasonable rate.

243. We disagree with MISO TOs' argument that this is not a case where the Commission fixed an error on rehearing of Opinion No. 551, and with Ameren's and Transource Energy's arguments that the new replacement base ROE established in granting rehearing of Opinion No. 551 can only be effective prospectively from the date of Opinion No. 569. MISO TOs contend that, while the Commission granted rehearing of Opinion No. 551 in part, it is unclear as to which issue presented on rehearing the Commission granted because none of the rehearing requests asked the Commission to adopt a new ROE methodology.[395] MISO TOs, instead, contend that opposing parties requested rehearing on the grounds that the composition of the DCF proxy group was incorrect, and that Commission should consider only DCF results, ignore the anomalous capital market conditions that impacted the DCF model inputs, and ignore cost of equity evidence produced by alternative models.[396] While it may be true that a party did not explicitly request that the Commission reach each and every exact decision that it made in Opinion No. 569, the Commission nonetheless acted within its discretion to reach its conclusions and these conclusions involved granting rehearing of the Commission's decision in Opinion No. 551 to establish a 10.32% base ROE as the new ROE under the second prong of section 206 in the First Complaint proceeding.

244. In Opinion No. 551, the Commission relied on the DCF analysis and looked to the CAPM, Risk Premium, and Expected Earnings models as corroborative evidence to support its decision. On rehearing, certain parties argued, as MISO TOs note, that the

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[393] *Ariz. Pub. Serv. Co.*, 26 FERC ¶ 61,087, at 61,221 (1984).

[394] *Id.*

[395] MISO TOs Rehearing Request at 85-86.

[396] *Id.* at 86.

Commission should have considered only DCF results and ignored those alternative models.[397] In Opinion No. 569, as modified in this order, the Commission granted rehearing to reach a logical middle ground that does not consider only DCF, as those parties requested, but does depart from Opinion No. 551 by considering only some of the other three models that the Commission initially considered in Opinion No. 551. Specifically, here we consider the CAPM and Risk Premium models in addition to the DCF model, but not the Expected Earnings model, which the Commission initially did consider in Opinion No. 551. In reaching its decision on rehearing of Opinion No. 551, the Commission is not limited to only reaching a conclusion that replicated every detail of a conclusion that a party had explicitly proposed.[398] In relevant part, the Commission, upon a party's application for rehearing, "shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing."[399] Accordingly, the Commission may modify its order on rehearing as it has here, because there exists no such limitation as a requirement that the Commission may only modify its order if the exact modification is explicitly proposed by a party on rehearing. The Commission found merit in some of the arguments against considering all of the non-DCF models but was not persuaded to ignore all of the models. Accordingly, it reached a conclusion arising from compromise that considered some, but not all, of the alternative models that were considered in Opinion No. 551. As a result of partially granting rehearing on these issues, the Commission granted rehearing of its decision to establish 10.32% as a new replacement base ROE in the First Complaint proceeding. Accordingly, this is a case where the Commission granted rehearing to modify Opinion No. 551, and that modified conclusion is effective as of the date of Opinion No. 551.

245. While the Commission's grant of rehearing of Opinion No. 551 is sufficient to justify the Commission's ordering of refunds from the date of Opinion No. 551—September 28, 2016—through the date of this order, the Commission's decision to order such refunds is further justified by the fact that it is correcting a legal error in granting rehearing to change the new just and reasonable ROE established for the First Complaint proceeding in Opinion No. 551. Although Ameren is correct that none of the Commission decisions in these proceedings have been vacated by a court, that does not mean that there was no legal error in the Commission's decisions in these proceedings. In *Emera Maine*, the D.C. Circuit found that the Commission failed to satisfy its dual burden under section 206 of the FPA by finding that the result of a single ROE analysis was sufficient to demonstrate that an existing base ROE was unjust and unreasonable if it exceeded that result and that such result was a just and reasonable

[397] *See id.* at 86.

[398] *See* 16 U.S.C. § 825*l*.

[399] *Id.*

replacement ROE. Opinion No. 551 and Initial Decision (II) in the Second Complaint proceeding both used the same reasoning that the D.C. Circuit found was insufficient to satisfy the Commission's burden under section 206. Accordingly, while no court has vacated a specific decision in this case, the rationale on which Opinion No. 551 and Initial Decision (II) in the Second Complaint proceeding are based has been rejected by the D.C. Circuit as in violation of section 206. As a result, those Commission decisions are based on a legal error identified by the D.C. Circuit. The fact that the court did not explicitly identify that legal error in a case involving a decision in these proceedings does not mean that there is no error in Opinion No. 551 and Initial Decision (II). To find otherwise would allow the Commission to continue to make decisions that are based on reasoning that has been found to be unlawful and only require the Commission to correct those decisions when a court has repeated its previous conclusion in every individual applicable case.

246. MISO TOs and Transource Energy also argue that the legal error doctrine does not apply here because the methodology adopted in Opinion No. 569 goes beyond what they contend is necessary to fix the problems identified by the *Emera Maine* court, and therefore represents a change in policy and not correction of a legal error. We disagree. The court in *Emera Maine* found that the Commission acted arbitrarily and outside of its statutory authority because its single ROE analysis failed to include an actual finding as to the lawfulness of the existing base ROE at issue. The court remanded the proceeding for the Commission to make that actual finding, but it did not specify exactly how the Commission needed to make that finding. In Opinion No. 569, as modified herein, the Commission concluded that the best way to make that finding in these proceedings in light of its statutory obligations was to revise its methodology for analyzing base ROEs under section 206 as explained herein. Accordingly, while MISO TOs and Transource Energy would prefer the Commission to arrive at this finding in a different way, that does not mean that the Commission's action is a change in policy instead of a correction of a legal error.

247. We are also not persuaded by arguments that the Commission should exercise its discretion to not order interest on the refunds for the period from the date of Opinion No. 551 through the date of this order replacing the base ROE set in in Opinion No. 551. While MISO TOs are correct that the Commission is not required to order that interest be paid on all refunds, we find that there are no equitable reasons that would warrant not ordering interest on the refunds ordered from the date of Opinion No. 551 through the date of this order. The parties to the First Complaint proceeding had notice that the base ROE established to be prospective from the date of Opinion No. 551 was subject to rehearing and therefore could be modified such that the modified rate would result in refunds, with interest pursuant to the Commission's authority under section 206. We are also not persuaded by MISO TOs' argument that the Commission should exercise its discretion to not require interest on the refunds because the status quo ante cannot be

fully restored since a separate Commission order "implicitly has recognized"[400] that some non-public utility members of MISO do not have a refund obligation relating to complaints that were filed prior to 2017.[401] As the precedent cited by MISO TOs provides, the Commission is not restricted to only requiring interest on refunds when it can completely restore the status quo ante, but rather, whether the status quo ante can be fully restored is merely a consideration that "may . . . offset . . . at least in part"[402] a full refund. MISO TOs also correctly recognize that "whether to order interest in crafting a remedy is a matter of Commission discretion."[403] MISO TOs have not persuaded us that the fact that some members of MISO may have different obligations with respect to the subject refunds is sufficient to use to our discretion to deny the complainants a full refund with interest. The payment of interest on refunds merely "ensures that the amounts to be refunded are, in fact, refunded through the addition of interest so that the recipient receives payment in inflation-adjusted dollars . . . to make the recipients whole,"[404] consistent with the Commission's "general policy of granting full refunds" for overcharges.'"[405] While we may exercise our discretion to decline to make recipients whole through the payment of interest on refunds, MISO TOs' argument on this point is not a sufficient reason to do so. On balance, we find that is more appropriate to ensure that the overcharged entities are made whole through the payment of interest on refunds than it is to decline to require interest because some members of MISO may have different obligations with respect to the subject refunds such that the refunds paid do not exactly reconstitute the status quo ante.

248. Transource Energy argues that the Commission should use its discretion to not order additional refunds for the First Complaint proceeding's 15-month refund period because customers benefitted from investments during the refund period.[406] We find that this argument is similarly unavailing. Transmission owners are constantly making new

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[400] MISO TOs Rehearing Request at 89.

[401] *Id.* at 88-89 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,050 at P 24).

[402] *Panhandle E. Pipe Line Co.*, 69 FERC ¶ 61,048, at 61,189 (1994) (quoting *Consumer Fed'n of America v. FPC*, 515 F.2d 347, 359 (D.C. Cir. 1975)).

[403] MISO TOs Rehearing Request at 87 (quoting *Transcon. Gas Pipe Line Corp.*, 71 FERC ¶ 61,108, at 61,361 (1995)).

[404] *La. Pub. Serv. Comm'n*, 153 FERC ¶ 61,033, at P 14 (2015).

[405] *Consolidated Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 972 (D.C. Cir. 2003).

[406] Transource Energy Rehearing Request at 38.

investments and changing investments during proceedings that may result in refund obligations. Therefore, to find that the existence of these investments alone would absolve such transmission owners from ordering refunds resulting from a Commission decision would mean that transmission owners would only owe refunds in the rarest of circumstances. We find that this would be contrary to the purpose of the refund obligation in section 206.

249. Consequently, we deny rehearing on this issue and find that, by granting rehearing of the decision in Opinion No. 551 to establish a new just and reasonable base ROE, and by acting to correct a legal error, it is appropriate to direct refunds, with interest, for the period from the effective date of the just and reasonable base ROE that was set in Opinion No. 551 which is being replaced in this order— September 28, 2016—through the date of this order, based on the new 10.02% base ROE established for the First Complaint proceeding in this order.

C. Second Complaint Proceeding Refunds

1. Rehearing Requests

250. CAPs argue that the Commission erred in not requiring refunds for the Second Complaint proceeding's refund period. They contend that the First Complaint and Second Complaint each challenged the base ROE in effect as of the date of filing of each complaint and had separate refund periods.[407] CAPs assert that, therefore, the mere fact that the two separate refund periods exceed 15 months does not mean that section 206 of the FPA is violated, "particularly in view of the fact that Commission orders set both refund periods, and the Commission itself acknowledged that the ROE in force when each complaint was filed was demonstrated to be unjust and unreasonable based on evidence of market conditions during the relevant study period."[408]

251. CAPs further contend that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding creates a loophole that utilities could exploit to vitiate the consumer protection intended by section 206. In particular, CAPs assert that a utility could make a tactical section 205 filing after a section 206 filing is signaled or underway to undermine section 206's refund and prospective relief remedies. CAPs argue that, for example, if an initial decision identifies a new just and reasonable base ROE resulting from a section 206 complaint, the subject utility could make a section 205 filing before issuance of a Commission order on the initial decision that reduces its base ROE to a level well above the base ROE the initial decision determined was just and reasonable, but just within the top end of what the initial decision identifies

[407] CAPs Rehearing Request at 52-53.

[408] *Id.* at 53.

as the zone of presumptively just and reasonable ROEs, such that the utility's proposed base ROE in the section 205 filing would likely be accepted by the Commission. CAPs argue that, under the Commission's rationale in Opinion No. 569, in such a case, the base ROE in the utility's section 205 filing would become the currently effective base ROE that the Commission would examine for purposes of acting on the initial decision, meaning that this base ROE would likely not be found unjust and unreasonable in the Commission's order on the initial decision because it falls within the zone of presumptively just and reasonable ROEs identified in the initial decision. CAPs contend that, in such a case, the utility would have successfully shielded itself both from refunds and from a prospective reduction down to the cost-based level found in the initial decision. CAPs argue that, because of this possibility, the Commission should reconsider its finding that the FPA requires section 206 relief to be denied if the rate in effect just before a final order applying section 206 is just and reasonable, or at least clarify how it would prevent such tactics from vitiating relief under section 206.[409]

252. CAPs further contend that, even if the Commission does not reverse its determination that the outcome of the Second Complaint was dependent on the outcome of the First Complaint, it still has and should exercise discretion to order refunds for the Second Complaint proceeding. CAPs assert that, because section 206 contains no deadline for the Commission to act on a complaint, where two complaints raising overlapping issues are pending before the Commission simultaneously, the order in which the Commission acts on the complaints is within the Commission's discretion. CAPs argue that the Commission should have acted on the Second Complaint before acting on rehearing of Opinion No. 551 because this would have kept prospective rates, which can affect future conduct, aligned with the most recent and accurate evidence of the MISO TOs' cost of equity. CAPs contend that, by acting in this sequence, MISO transmission customers would have been entitled to refunds for the Second Complaint proceeding's refund period and the First Complaint proceeding's refund period because the ROE set by an order in the Second Complaint could not be deemed to be the "existing" ROE for purposes of deciding the First Complaint. CAPs assert that, therefore, the Commission's rationale for denying refunds in the Second Complaint proceeding effectively claims that the Commission's procedural decisions can expand or contract the statutory rights of public utility customers.[410]

253. LPSC argues that Opinion No. 569 interprets section 206 to mean that the Commission must decide whether the rate that is "currently effective" at the time it issues its opinion is just and reasonable, as opposed to the rate that was in effect at the time the

[409] *Id.* at 53-54.

[410] *Id.* at 56-59.

complaint was filed and contends that this interpretation violates the FPA.[411] LPSC contends that section 206 provides that the Commission shall determine the just and reasonable rate, if the Commission determines that the rate "demanded, observed, charged, or collected by any public utility . . . is unjust, unreasonable, unduly discriminatory or preferential."[412] LPSC asserts that Opinion No. 569 is inconsistent with this plain language because it requires an analysis of whether a new rate that had never been charged or collected by the utility is just and reasonable. LPSC contends that the MISO TOs have never "demanded, observed, charged, or collected" the 9.88% ROE that was established in Opinion No. 569 from their customers, so the FPA could not have intended for that to be the rate analyzed by the Commission.[413]

254. LPSC argues that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding would prevent the Commission from ever granting refunds in a second ROE proceeding, even if the Commission found that the newly effective ROE that resulted from the first ROE proceeding had become unjust and unreasonable by the time the second complaint was filed. LPSC contends that this is the case because section 206 provides for refunds to "persons who have paid those rates" but no person would have paid the rate established in such a first complaint proceeding.[414]

255. LPSC also contends that the Commission's interpretation on this point is inconsistent with the Commission's precedent in *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*[415] LPSC asserts that, in that case, the Commission rejected a company's argument that a 2013 ROE complaint should be dismissed because it served only to extend the refund effective period associated with a 2012 ROE complaint, and explained that, "In assessing the 2013 Complaint, the relevant comparison is between the current ROE and the ROE sought in the 2013 Complaint."[416]

256. LPSC further argues that Opinion No. 569 is also arbitrary because its conclusions rely entirely on the order that the Commission decides the ROE proceedings, but there is no statute or regulation that requires the Commission to resolve section 206 proceedings

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[411] LPSC Rehearing Request at 17-19.

[412] *Id.* at 19 (citing 16 U.S.C. § 824e (2018)).

[413] *Id.*

[414] *Id.* at 19-20.

[415] 151 FERC ¶ 61,126 (2015).

[416] LPSC Rehearing Request at 21 (citing *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 151 FERC ¶ 61,126 at P 24).

chronologically. LPSC contends that refunds could have been granted for the second complaint proceeding and a different ROE would have applied prospectively if Opinion No. 569 had resolved the second complaint proceeding first. LPSC asserts that Congress did not intend to give the Commission the power to decide the justness and reasonableness of rates and whether refunds should be granted based on the order that it chooses to decide complaints.[417]

257. In addition, LPSC argues that Opinion No. 569 is inconsistent with the Commission's precedent that a second ROE complaint can be filed and a second refund effective period can be ordered, as long as the second complaint is based on new analyses and data. LPSC contends that, "Contrary to its precedent, Opinion No. 569 now finds that determining whether the ROE in a second ROE complaint proceeding is unjust and unreasonable by analyzing the ROE that was in effect when the complaint was filed would effectively extend the statutory fifteen-month refund effective period."[418] LPSC argues that, in *Firstenergy Service Co. v. FERC*, 758 F.3d 346 (D.C. Cir. 2014), the D.C. Circuit stated that "FERC is required to evaluate a 206 complaint as to existing rates specifically because they might have become unjust and unreasonable by intervening shifts in circumstances"[419] and that the Commission should do the same here and rule that the rate in effect at the time the Second Complaint was filed should be analyzed to assess possible "intervening shifts in circumstances."[420]

258. RPGI similarly argues that the Commission's interpretation of section 206 to not permit refunds for the Second Complaint proceeding is unsupported. RPGI asserts that the Commission's interpretation sets up a scenario in which the ROE in force on a second complaint's date of filing becomes virtually irrelevant. RPGI contends that a complainant would know that, if it filed, the benchmark against which its case would be evaluated would not be the ROE in effect on the date the second complaint would be filed—which is known—but rather the ROE set by the first proceeding and where it falls in the second proceeding's updated zone of reasonableness, neither of which is known at the second proceeding's outset. RPGI asserts that, thus, after Opinion No. 569, filing a second complaint upon the expiration of a first complaint's refund period represents such

[417] *Id.* at 21-23.

[418] *Id.* at 24.

[419] *Id.* at 27-28 (citing *Firstenergy Service Co. v. FERC*, 758 F.3d at 356).

[420] *Id.*

a high risk of a "no-change" outcome as to effectively bar successive complaints, even if the data from the second proceeding supports an ROE lower than that set by the first.[421]

259. RPGI argues that, if the Commission's concern is that successive complaints require it to make duplicative findings of one ROE's unlawfulness, then it could consolidate proceedings. RPGI further contends that, if the Commission's concern is the effect of successive refund periods on the MISO TOs, the appropriate course of action is seeking a statutory change, not adopting a strained statutory interpretation.[422]

2. Commission Determination

260. We deny rehearing on this issue. We continue to find, as the Commission did in Opinion No. 569, that, for purposes of deciding whether a rate charged by a public utility is unjust and unreasonable and determining a new just and reasonable rate "to be thereafter observed" pursuant to section 206(a) of the FPA, we must assess whether the public utility's currently effective rate is unjust and unreasonable, not some earlier rate that may have been in effect when the complaint was filed but has now been superseded. As explained in Opinion No. 569, in the context of successive, or pancaked, complaints like those in these proceedings, if the Commission's analysis in the successive complaint analyzed some earlier rate that may have been in effect when the complaint was filed but has since been superseded, it would permit the Commission to order refunds for a period beyond the 15-month statutory refund period based on a single decision in the preceding complaint decision. We find that this would allow the Commission to use a single decision as the predicate for issuing refunds beyond the refund period applicable to that decision, which would exceed the refund authority granted to the Commission in section 206.

261. CAPs argue that the First Complaint and Second Complaint each challenged the base ROE in effect as of the date of filing of each complaint and had separate refund periods, and the mere fact that the two separate refund periods exceed 15 months does not mean that section 206 is violated. CAPs misinterpret the Commission's finding in Opinion No. 569. In Opinion No. 569, the Commission did not find that the mere fact that the First Complaint and Second Complaint proceedings had separate refund periods that combined exceed 15 months rendered the Commission unable to issue refunds in the Second Complaint proceeding. It would have been possible for the Commission to order refunds for the refund periods in both complaint proceedings if the base ROE resulting from resolution of the First Complaint proceeding was no longer just and reasonable based on the facts and circumstances of the Second Complaint proceeding. However, complainants did not show that the existing rate reviewed in the Second Complaint

[421] RPGI Rehearing Request at 17-21.

[422] *Id.* at 22-23.

proceeding was unjust and unreasonable under the facts and circumstances of that proceeding.

262. Both complaints challenged the MISO TOs' base ROE, and the Commission established a new just and reasonable base ROE in the First Complaint proceeding that was filed first chronologically. As discussed above, the Commission found that it was required to review that new base ROE as the existing rate for purposes of the Second Complaint and complainants did not show that this existing rate was unjust and unreasonable. The Commission then found that section 206 provides that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding because section 206 only permits refunds in proceedings where the Commission sets a new rate to be "thereafter observed and in force."[423] As a result, the Commission found that it did not have authority under section 206 to order refunds in the Second Complaint proceeding because it did not grant prospective relief by establishing a new base ROE in that proceeding. The Commission further explained that ordering refunds in the Second Complaint proceeding even though it did not grant prospective relief in that proceeding would in fact allow its determination in the First Complaint proceeding to serve as the predicate for two 15-month refund periods, which is beyond the Commission's authority in section 206. Accordingly, the fact that the First Complaint and Second Complaint proceedings had separate refund periods that together exceeded 15 months did not render the Commission unable to issue refunds in the Second Complaint proceeding. Rather, it was the fact that the Commission could not grant prospective relief in the Second Complaint proceeding because the complainants did not show that the rate that was reviewed in that Second Complaint proceeding was unjust and unreasonable. Had the complainants made that showing, the Commission could have ordered refunds in the Second Complaint proceeding, regardless of the fact that the refund periods in the First Complaint proceeding and Second Complaint proceeding add up to more than 15 months. However, that was not the case and consequently we find CAPs' argument on this point unavailing.

263. CAPs argue that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding creates a loophole pursuant to which a utility could make a tactical section 205 filing after a section 206 filing is signaled or underway to undermine section 206's refund and prospective relief remedies. CAPs assert that such a filing could, for example, propose to reduce the utility's base ROE to a level well above the base ROE the initial decision determined was just and reasonable, but just within the top end of what the initial decision identifies as the zone of presumptively just and reasonable ROEs, such that the utility's proposed base ROE in the section 205 filing would likely be accepted by the Commission and then become the currently effective base ROE that the Commission would examine for purposes of acting

[423] Opinion No. 569, 169 FERC ¶ 61,129 at P 568.

on the initial decision. This argument does not persuade us that our interpretation is inappropriate. As an initial matter, we note that the presumptively just and reasonable ranges applied in this order are limited to our analysis of complaints filed under section 206. There is no section 205 filing before us in this proceeding and we are not making any determinations regarding whether or how the presumptively just and reasonable ranges used in this order would apply in the context of a section 205 filing. Moreover, if a utility were to make such a tactical section 205 filing proposing a new base ROE while a section 206 proceeding challenging the utility's base ROE is still pending a final Commission decision, then the Commission could consider such a section 205 filing in light of the pending section 206 proceeding. "The Commission has broad discretion to structure its proceedings so as to resolve a controversy in the way it best sees fit,"[424] and, in addressing such a section 205 filing, the Commission could consider the common issues that would likely be raised by a section 205 filing to change the same base ROE that is being challenged in a pending section 206 proceeding. For example, in analogous circumstances, the Commission consolidated a rate filing pursuant to section 4 of the Natural Gas Act (NGA) with an ongoing complaint proceeding pursuant to section 5 of the NGA involving the same rates. There the Commission noted that "KCC asserts that Southwest Gas's instant section 4 rate filing is nothing more than an attempt to circumvent the ongoing section 5 complaint proceeding"[425] and found that "the section 4 filing appears as an outgrowth of the section 5 complaint proceeding"[426] for which consolidation would "provide the most efficient and effective forum to handle issues common to both proceedings."[427] Any section 205 filing like the type suggested by CAPs would be considered by the Commission in light of any other proceedings

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[424] *PJM Transmission Owners*, 120 FERC ¶ 61,013, at P 12 (2007). *See also Ameren Energy Generating Co.,* 108 FERC ¶ 61,081, at P 23 (2004) ("The courts have repeatedly recognized that the Commission has broad discretion in managing its proceedings."); *Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003) (citing *Telecomm. Resellers Assoc. v. FCC*, 141 F.3d 1193, 1196 (D.C. Cir. 1998) (stating that administrative agencies enjoy broad discretion to manage their own dockets); *FPC v. Transcontinental Gas Pipe Line Corp.*, 423 U.S. 326, 333 (1976) (stating that agencies can determine how best proceed to develop the needed evidence); *Richmond Power & Light v. FERC*, 574 F.2d 610, 624 (D.C. Cir. 1978) (stating that agencies have wide leeway in controlling their calendars)).

[425] *Panhandle Complainants v. Sw. Gas Storage Co.*, 120 FERC ¶ 61,207, at P 19 (2007).

[426] *Id.* P 20.

[427] *Id.* P 21.

involving common issues, including section 206 proceedings.[428] We do not believe that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding would somehow allow utilities to make section 205 filings that would dictate or otherwise limit the Commission's ability to appropriately determine just and reasonable rates in section 206 proceedings.

264. LPSC argues that Opinion No. 569's decision to not order refunds in the Second Complaint proceeding is inconsistent with section 206 because section 206 requires the Commission to determine whether a rate "demanded, observed, charged, or collected by any public utility . . . is unjust, unreasonable, unduly discriminatory or preferential"[429] but MISO TOs have never "demanded, observed, charged, or collected" the base ROE that was established in the First Complaint proceeding from their customers, but that is the rate that the Commission analyzed in making its determination in the Second Complaint proceeding. We find this argument unavailing. While at the time the Second Complaint was filed, the new just and reasonable rate established in the First Complaint proceeding had not yet been demanded, observed, charged or collected, the Commission's decision in the First Complaint proceeding made the new base ROE established in that proceeding the rate that was demanded, observed, charged and collected for the First Complaint proceeding's refund period. Therefore, when the Commission analyzed the new just and reasonable rate established in the First Complaint proceeding in making its determination in the Second Complaint proceeding, that rate was the one demanded, observed, charged and collected for the First Complaint proceeding's refund period, which is consistent with the language of section 206. The fact that the Commission acted on the successive complaints in the First Complaint and Second Complaint proceedings in a single order instead of in two separate sequential ones does not render the new base ROE established in the First Complaint proceeding a fiction that is not actually applied by the MISO TOs. Rather, the Commission's decision in the First Complaint proceeding made the rate established there the rate "demanded, observed, charged, or collected" for purposes of the First Complaint proceeding and the Commission then reviewed that rate as the existing rate in making its decision on the Second Complaint which followed the First Complaint. We are not persuaded that this analysis is inconsistent with section 206.

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[428] *See, e.g.*, *Mobil Oil Explor. & Prod. SE Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230 (1991) ("An agency enjoys broad discretion in determining how best to handle related, yet discrete, issues in terms of procedures."); *Nadar v. FCC*, 520 F.2d 182, 195 (D.C. Cir. 1975) ("[T]his court has upheld in the strongest terms the discretion of regulatory agencies to control the disposition of their caseload.").

[429] LPSC Rehearing Request at 19 (citing 16 U.S.C. § 824e).

265. CAPs and LPSC argue that the Commission is not required to act on the First Complaint proceeding first and should have acted on the Second Complaint proceeding first. They contend that there is no requirement that the Commission resolve section 206 proceedings chronologically. As an initial matter, we note that, "The Commission has broad discretion to structure its proceedings so as to resolve a controversy in the way it best sees fit."[430] The Commission "is generally master of its own calendar and procedures."[431] In these proceedings, we find that it is appropriate to act on the First Complaint proceeding first and then the Second Complaint proceeding. The Commission permitted the Second Complaint because it was "was based on financial data from a different time period, and produced a different proxy group, than the DCF analysis set forth in the [First Complaint]."[432] In that order, the Commission explained that it "has allowed multiple complaints regarding the same ROE, where the subsequent complaints are based on 'new, more current data.'"[433] Accordingly, the premise for permitting the Second Complaint was that it was based on different, more current data, than the data in the First Complaint proceeding. We find that it is appropriate to address the First Complaint first because the Commission must first determine what the final data and results from the First Complaint are before determining whether the Second Complaint can be granted based on how the Second Complaint's data have changed as compared to the data in the First Complaint. Moreover, we find that it would not be appropriate to follow the approach suggested by CAPs and LPSC because it could force the Commission to delay action on a preceding complaint that is likely closer to resolution until it has first acted on a successive complaint because that successive complaint is

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[430] *PJM Transmission Owners*, 120 FERC ¶ 61,013 at P 12.

[431] *Stowers Oil and Gas Co.*, 27 FERC ¶ 61,001 (1984); *see also Ameren Energy Generating Co.,* 108 FERC ¶ 61,081 at P 23 ("The courts have repeatedly recognized that the Commission has broad discretion in managing its proceedings.); *Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003) (citing *Telecomm. Resellers Assoc. v. FCC*, 141 F.3d 1193, 1196 (D.C. Cir. 1998) (stating that administrative agencies enjoy broad discretion to manage their own dockets); *FPC v. Transcontinental Gas Pipe Line Corp.*, 423 U.S. 326, 333 (1976) (stating that agencies can determine how best proceed to develop the needed evidence); *Richmond Power & Light v. FERC*, 574 F.2d 610, 624 (D.C. Cir. 1978) (stating that agencies have wide leeway in controlling their calendars)).

[432] MISO II Rehearing Order, 156 FERC ¶ 61,061 at P 34.

[433] *Id.* P 33 (quoting *Consumer Advocate Div. of the Pub. Serv. Of West Virginia v. Allegheny Generating Co.*, 67 FERC ¶ 61,288, *order on reh'g*, 68 FERC ¶ 61,207, at 61,998 (1994)).

"aligned with the most recent and accurate evidence."[434] This could further delay Commission action on section 206 complaint proceedings that are often already very protracted. In addition, CAPs' and LPSC's approach would not always benefit ratepayers over utilities. For example, it is possible that, in resolving a successive complaint first, ratepayers would be subject a higher rate during such a complaint's refund period than they would have been subject to if the preceding complaint resulted in a prospectively effective rate that overlapped with the successive complaint's refund period which was lower than the rate resulting from the successive complaint. Accordingly, we find that it is appropriate to address the complaints in these proceedings in chronological order by deciding the First Complaint before deciding the Second Complaint.

266. RPGI argues that, if the Commission's concern in deciding to not order refunds in the Second Complaint proceeding was that it would be required to make duplicative findings of one ROE's unlawfulness, then it could consolidate the First Complaint and Second Complaint proceedings. We find this argument unavailing. The Commission has explained that "[i]n general, the Commission consolidates matters only if . . . consolidation will ultimately result in greater administrative efficiency."[435] However, these proceedings have progressed through hearing, initial decision and, in the case of the First Complaint proceeding, Commission decision, separately with separate records. At this point there would be no greater administrative efficiency in consolidating these two proceedings because they are already close to final resolution. Moreover, RPGI does not explain how consolidation would eliminate the need to identify the existing rate to be analyzed in the Second Complaint proceeding and then determine whether refunds could be issued based on the Commission's analysis of that rate under section 206. Thus, RPGI has not explained how consolidation would change the analysis underlying our decision to not order refunds in the Second Complaint proceeding.

267. RPGI also contends that, if the Commission's concern in making its decision in Second Complaint proceeding is the effect of successive refund periods on the MISO TOs, the appropriate course of action is seeking a statutory change, not adopting a strained statutory interpretation. However, here we must determine how to act in these section 206 complaint proceedings and in order to do so we must determine how to interpret and apply section 206 to these proceedings. The issue before us is not whether it would be appropriate or preferable to seek a statutory change. We must apply the statute as it exists to these proceedings. The fact that RPGI would prefer that the Commission adopt a different interpretation does not mean that the Commission had the option of not applying section 206 as it exists to these proceedings. For the reasons discussed in this order, we find that the application of section 206 to the Second

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[434] *See* CAPs Rehearing Request at 59.

[435] *See, e.g.*, *Startrans IO, LLC*, 122 FERC ¶ 61,253, at P 25 (2008).

Complaint proceeding requires us to dismiss the complaint and not order refunds in that proceeding. Accordingly, we find that RPGI's argument on this point does not persuade us to grant rehearing of our decision to not order refunds in the Second Complaint proceeding.

XIX. Conclusion

268. For the reasons discussed above, we grant in part and deny in part the requests for rehearing of Opinion No. 569. In particular, we require the MISO TOs to adopt a 10.02% base ROE effective September 28, 2016, the date Opinion No. 551 initially required the MISO TOs to adopt a 10.32% ROE. As discussed above, we therefore require the MISO TOs to provide refunds based on that 10.02% base ROE, with interest, for the First Complaint proceeding's 15-month refund period from November 12, 2013 through February 11, 2015, and for the period from September 28, 2016 to the date of this order. Further, as discussed above we are denying rehearing of the Commission's dismissal of the Second Complaint in Opinion No. 569 and its finding that no refunds will be ordered in the Second Complaint proceeding.

The Commission orders:

(A) Rehearing of Opinion No. 569 is granted in part and denied in part, as discussed in the body of this order.

(B) MISO TOs' base ROE is set at 10.02% with a total or maximum ROE including incentives not to exceed 12.62%, effective as of September 28, 2016, as discussed in the body of this order.

(C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2019), by December 23, 2020, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 to the date of this order, as discussed in the body of this order.

(D) MISO and MISO TOs are directed to file a refund report a detailing the principal amounts plus interest paid to each of their customers by December 23, 2020.

By the Commission. Commissioner Glick is concurring in part and dissenting in part in a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix I: Risk Premium Results

Risk Premium Model Results

Current Equity Risk Premium	MISO I	MISO II
Average Yield Over Study Period	6.10%	6.02%
Baa Utility Bond Yield	4.65%	5.41%
Change in Bond Yield	-1.45%	-0.61%
Risk Premium/Interest Rate Relationship	-0.7006	-0.6866
Adjustment to Average Risk	1.02%	0.42%
Average Risk Premium over Study Period	4.43%	4.46%
Adjusted Risk Premium	**5.45%**	**4.88%**
Implied Cost of Equity		
Baa Utility Bond Yield	4.65%	5.41%
Adjusted Equity Risk Premium	5.45%	4.88%
Risk Premium Cost of Equity	**10.10%**	**10.29%**

Risk Premium Model Inputs

Docket Number	Utility	Type	Date	Base ROE	Baa Bond Yield	Implied Risk Premium
ER05-515	BG&E	Settlement - Uncontested	Feb-06	10.80	6.07	4.73
ER05-515	BG&E	Settlement - Uncontested	Feb-06	11.30	6.07	5.23
ER05-925	Westar	Settlement - Uncontested	Jun-06	10.80	6.36	4.44
ER07-284	SDG&E	Settlement - Uncontested	Feb-07	11.35	6.14	5.21
ER06-787	Idaho Pwr	Settlement - Uncontested	May-07	10.70	6.15	4.55
ER06-1320	Wisconsin Elec. Pwr	Settlement - Uncontested	May-07	11.00	6.15	4.85
ER07-583	Commonwealth Edison	Settlement - Uncontested	Sep-07	11.00	6.41	4.59
ER06-1549	Duquesne	Settlement - Uncontested	Sep-07	10.90	6.41	4.49
ER08-92	VEPCO	Order	Oct-07	10.90	6.43	4.47
ER08-374	Atlantic Path	Order	Nov-07	10.65	6.44	4.21
ER08-413	Startrans IO	Order	Nov-07	10.65	6.44	4.21
ER08-396	Westar	Declaratory order.	Nov-07	10.80	6.44	4.36
ER08-686	Pepco Holdings	Order	Jan-08	11.30	6.41	4.89
ER07-562	Allegheny	Settlement	Feb-08	11.20	6.42	4.78

ER07-1142	Ariz. Pub. Service	Settlement - uncontested	Apr-08	10.75	6.54	4.21
ER08-1207	VEPCO	Order	May-08	10.90	6.62	4.28
ER08-1402	Duqesne	Order	Jun-08	10.90	6.69	4.21
ER08-1423	Pepco Holdings	Order	Jun-08	10.80	6.69	4.11
ER08-1584	Black Hlls	Settlement - Uncontested	Jun-08	10.80	6.69	4.11
ER09-35/36	Tallgrass / Prairie Wind	Commission Order	Jul-08	10.80	6.80	4.00
ER09-249	Public Service Elec. & Gas	Accepted by FERC	Aug-08	11.18	6.86	4.32
ER09-548	ITC Great Plains	Settlement - Uncontested	Sep-08	10.66	6.94	3.72
ER09-75	Pioneer	Order	Sep-08	10.54	6.94	3.60
ER09-187	SoCal Edison	Order on Paper Hearing	Sep-08	10.04	6.94	3.10
ER08-375	SoCal Edison	Order on Paper Hearing	Nov-08	10.55	7.60	2.95
ER09-745	Baltimore Gas & Elec.	Accepted by FERC	Dec-08	11.30	7.80	3.50
ER07-1069	AEP - SPP Zone	Settlement - Uncontested	Jan-09	10.70	7.95	2.75
ER09-681	Green Power Express	Commission Order	Jan-09	10.78	7.95	2.83
ER08-281	Oklahoma Gas & Elec.	Settlement - Uncontested	Apr-09	10.60	8.13	2.47
ER08-1457	PPL Elec. Utilities Corp.	Settlement - Uncontested	Apr-09	11.00	8.13	2.87

ER08-1457	PPL Elec. Utilities Corp.	Settlement - Uncontested	Apr-09	11.14	8.13	3.01
ER08-1588	Kentucky Utilities Co.	Settlement - Uncontested	Apr-09	11.00	8.13	2.87
ER08-552	Niagara Mohawk	Settlement - Uncontested	Jul-09	11.00	7.62	3.38
ER09-628	National Grid Generation LLC	Settlement - Uncontested	Aug-09	10.75	7.39	3.36
ER08-313	Southwestern Public Service Co.	Settlement - Uncontested	Aug-09	10.77	7.39	3.38
ER10-160	SoCal Edison	Order on Paper Hearing	Sep-09	10.33	7.08	3.25
ER08-1329	AEP - PJM Zone	Settlement - Uncontested	Mar-10	10.99	6.20	4.79
ER10-230	Kansas City Power & Light Co.	Settlement - Uncontested	Aug-10	10.60	6.05	4.56
ER10-355	AEP Transcos - PJM	Settlement - Contested	Aug-10	10.99	6.05	4.95
ER10-355	AEP Transcos - SPP	Settlement - Contested	Aug-10	10.70	6.05	4.66
ER11-1952	SoCal Edison	Order	Sep-10	10.30	5.93	4.37
EL11-13	Atlantic Grid Operations	Declaratory Order	Oct-10	10.09	5.84	4.26
ER11-2895	Duke Energy Carolinas	Settlement - Initial Filing	Oct-10	10.20	5.84	4.37
ER11-2377	Northern Pass Tx	Order	Nov-10	10.40	5.79	4.62
ER12-2300	PSCo	Order	Nov-10	10.25	5.79	4.47

ER10-1377	Northern States Power Co. (MN)	Settlement - Uncontested	Mar-11	10.40	5.94	4.46
ER10-992	Northern States Power Co.	Settlement - Uncontested	Apr-11	10.20	6.00	4.20
ER10-516	South Carolina Electric and Gas	Settlement - Uncontested	Apr-11	10.55	6.00	4.55
ER11-4069	RITELine	Order	May-11	9.93	5.98	3.95
ER12-296	PSEG	Order	Aug-11	11.18	5.71	5.47
ER08-386	PATH	Settlement - uncontested	Sep-11	10.40	5.57	4.83
ER11-2560	Entergy Arkansas, Inc.	Settlement - Uncontested	Dec-11	10.20	5.21	4.99
ER11-2853	PSCo	Settlement - Uncontested	Mar-12	10.10	5.08	5.03
ER11-2853	PSCo	Settlement - Uncontested	Mar-12	10.40	5.08	5.33
ER12-1378	Cleco	Settlement - Uncontested	Nov-12	10.50	4.74	5.77
ER12-2554	Transource Missouri	Settlement - Uncontested	Jan-13	9.80	4.65	5.16
ER12-778	Puget Sound Energy	Settlement - Uncontested	Jan-13	9.80	4.65	5.16
ER12-778	Puget Sound Energy	Settlement - Uncontested	Jan-13	10.30	4.65	5.66
ER11-3643	PacifiCorp Inc.	Settlement - Uncontested	Feb-13	9.80	4.62	5.18
ER12-1650	Maine Public Service Co.	Settlement - Uncontested	Feb-13	9.75	4.62	5.13

ER11-3697	SoCal Edison	Settlement - Uncontested	Jul-13	9.30	4.82	4.49
ER13-941	San Diego Gas and Electric	Settlement - Uncontested	Jan-14	9.55	5.22	4.33
ER12-1589	PSCo	Settlement	Aug-14	9.72	4.76	4.96
ER12-91	Duke Energy Ohio	Settlement - Uncontested	Sep-14	10.88	4.73	6.15
EL12-101	Niagara Mohawk	Settlement - Uncontested	Jan-15	9.80	4.66	5.14
ER13-685	Public Service Company New Mexico	Settlement - Uncontested	Feb-15	10.00	4.62	5.38
ER14-1661	MidAmerican Central California	Settlement - Uncontested	Mar-15	9.80	4.58	5.22
ER15-303	American Transmission Systems, Inc.	Settlement - Uncontested	May-15	9.88	4.58	5.30
ER15-303	American Transmission Systems, Inc.	Settlement - Uncontested	May-15	10.56	4.58	5.98
EL14-93	Westar Energy	Settlement - Uncontested	May-15	9.80	4.58	5.22
EL12-39	Duke Energy Florida	Settlement - Uncontested	Jun-15	10.00	4.65	5.35
ER14-192	SPS	Settlement - Uncontested	Jul-15	10.00	4.79	5.21
ER13-2428	Kentucky Utilities	Settlement - Uncontested	Jul-15	10.25	4.79	5.46
ER14-2751	XEST	Settlement - Uncontested	Sep-15	10.20	5.07	5.13

ER15-572	New York Transco LLC	Settlement - Uncontested	Oct-15	9.50	5.23	4.27
ER15-2237	Kanstar Transmission LLC	Settlement - Uncontested	Dec-15	9.80	5.41	4.39
ER15-2114	Transource West Virginia	Settlement - Uncontested	Dec-15	10.00	5.41	4.59

*Highlighted cases only included in MISO II

Cases removed from the Risk Premium Model

As noted above, the Commission refined the Risk Premium Model by, among other things, removing some cases from the analysis. A full list of those cases, along with the reason for their removal, is below:

Cases removed because the utility was merely adopting an existing ROE, such as the MISO ROE, without consideration of whether that ROE would be determined to be just and reasonable under fresh analysis:

- EL08-77, *Central Maine Power Co.*
- ER08-1548, *Northeast Utilities Service Co.*
- ER09-14, *NSTAR Elec. Co.*
- ER07-694, *New England Power Co.*
- EL10-80, *Ameren*
- ER12-1593, *DATC Midwest Holdings*
- ER12-2681, *ITC Holdings*

Cases removed because the ROE was clearly not under consideration:

- ER08-10, *Pepco Holdings, Inc.*
- ER11-3352, *PJM and Public Service Enterprise Group*

Cases removed for being duplicative:

- EL13-86, *Public Service Co. of Colorado*

Cases removed because the ROE was set for a definite future date, and the Commission could not have evaluated a risk premium for a future date:

- ER08-1457, *PPL Elec. Utilities Corp.*[436]

Cases removed because the test period predates 2006:

- EL05-19, *Golden Spread Electric Cooperative, Inc.*
- ER05-154, *Bangor Hydro Electric Company*

[436] Only the 11.18% was removed from consideration. The other two resulting ROEs, because they were not solely applied to a future period, are still included in the analysis.

Appendix II: DCF Results

MISO I DCF Results

Line	Company	Unadjusted Dividend Yield	Short-Term	Long-Term	Composite Growth	Dividend Yield Adjustment	Adjusted Dividend Yield	DCF Results
			Yahoo! Finance	GDP		One-Step		
1	Consolidated Edison, Inc.	4.14%	2.38%	4.39%	2.78%	101.19%	4.19%	6.97%
2	Public Service Enterprise Group	3.74%	2.95%	4.39%	3.24%	101.48%	3.80%	7.03%
3	PPL Corporation	4.39%	2.23%	4.39%	2.66%	101.12%	4.44%	7.10%
4	CenterPoint Energy, Inc.	4.69%	1.91%	4.39%	2.41%	100.96%	4.73%	7.14%
5	IDACORP Inc.	3.04%	4.00%	4.39%	4.08%	102.00%	3.10%	7.18%
6	OGE Energy Corp.	3.09%	4.00%	4.39%	4.08%	102.00%	3.15%	7.23%
7	Westar Energy Inc.	3.74%	3.40%	4.39%	3.60%	101.70%	3.80%	7.40%
8	Portland General Electric Co.	3.11%	4.70%	4.39%	4.64%	102.35%	3.18%	7.82%
9	DTE Energy Co.	3.38%	4.51%	4.39%	4.49%	102.26%	3.46%	7.94%
10	PG&E Corp.	3.39%	4.71%	4.39%	4.65%	102.36%	3.47%	8.12%
11	The Southern Co.	4.62%	3.32%	4.39%	3.53%	101.66%	4.70%	8.23%
12	SCANA Corp.	3.91%	4.30%	4.39%	4.32%	102.15%	3.99%	8.31%
13	Xcel Energy Inc.	3.68%	4.69%	4.39%	4.63%	102.35%	3.77%	8.40%
14	NorthWestern Corp.	3.60%	5.00%	4.39%	4.88%	102.50%	3.69%	8.57%
15	Duke Energy Corp.	4.05%	4.49%	4.39%	4.47%	102.25%	4.14%	8.61%
16	American Electric Power Co. Inc.	3.68%	5.08%	4.39%	4.94%	102.54%	3.77%	8.72%
17	Vectren Corp.	3.46%	5.50%	4.39%	5.28%	102.75%	3.56%	8.83%
18	Alliant Energy Corp.	3.50%	5.45%	4.39%	5.24%	102.73%	3.60%	8.83%

19	Avista Corp.	3.93%	5.00%	4.39%	4.88%	102.50%	4.03%	8.91%
20	NextEra Energy, Inc.	2.94%	6.27%	4.39%	5.89%	103.14%	3.03%	8.93%
21	Pinnacle West Capital Corp.	3.74%	5.30%	4.39%	5.12%	102.65%	3.84%	8.96%
22	Empire District Electric Co.	4.12%	5.00%	4.39%	4.88%	102.50%	4.22%	9.10%
23	Dominion Resources, Inc.	3.58%	5.89%	4.39%	5.59%	102.95%	3.69%	9.28%
24	Eversource Energy (Northeast Utilities)	3.27%	6.60%	4.39%	6.16%	103.30%	3.38%	9.54%
25	Ameren Corp.	3.91%	5.85%	4.39%	5.56%	102.93%	4.02%	9.58%
26	El Paso Electric Co.	3.01%	7.00%	4.39%	6.48%	103.50%	3.12%	9.59%
27	ALLETE Inc.	3.85%	6.00%	4.39%	5.68%	103.00%	3.97%	9.64%
28	CMS Energy Corp.	3.35%	6.73%	4.39%	6.26%	103.37%	3.46%	9.72%
29	Great Plains Energy, Inc.	3.65%	6.37%	4.39%	5.97%	103.19%	3.77%	9.74%
30	Otter Tail Corp.	4.06%	6.00%	4.39%	5.68%	103.00%	4.18%	9.86%
31	Black Hills Corp.	3.28%	7.00%	4.39%	6.48%	103.50%	3.39%	9.87%
32	Sempra Energy	2.59%	7.93%	4.39%	7.22%	103.97%	2.69%	9.91%
33	Exelon	3.64%	6.81%	4.39%	6.33%	103.41%	3.76%	10.09%
34	PNM Resources	2.85%	8.56%	4.39%	7.73%	104.28%	2.97%	10.70%
35	UIL Holdings	3.59%	7.79%	4.39%	7.11%	103.90%	3.73%	10.84%
36	TECO Energy	4.61%	7.68%	4.39%	7.02%	103.84%	4.79%	11.81%
37	ITC Holdings Corp.	1.76%	11.66%	4.39%	10.21%	105.83%	1.86%	12.07%
38	Unitil Corp.	Merger						
39	MGE Energy	Merger						
40	Edison International	2.66%	0.37%	4.39%	1.17%	100.19%	2.66%	4.38%
41	FirstEnergy Corp.	3.97%	-0.64%	4.39%	0.37%	99.68%	3.96%	5.01%
42	Entergy Corp.	4.21%	-0.48%	4.39%	0.49%	99.76%	4.20%	5.36%

Moodys Baa Utility Bonds	4.65%
Low With Outlier Test	6.97%
High	12.07%

Midpoint	9.52%
Low-End Outlier Test	6.47%
High-End Outlier Test	17.67%
Mean	8.93%

MISO II DCF Results

			Short-Term	Long-Term		Dividend Yield Adjustment		
Line	Company	Unadjusted Dividend Yield	Yahoo! Finance	GDP	Composite	One-Step	Adjusted Dividend Yield	DCF Results
1	Consol. Edison, Inc.	4.08%	2.95%	4.35%	3.23%	101.48%	4.14%	7.37%
2	Westar Energy Inc.	3.70%	3.50%	4.35%	3.67%	101.75%	3.76%	7.43%
3	Portland General Electric Co.	3.33%	4.11%	4.35%	4.16%	102.06%	3.40%	7.56%
4	Vectren Corp.	3.10%	5.00%	4.35%	4.87%	102.50%	3.18%	8.05%
5	Amer. Elec. Power Co., Inc.	3.84%	4.47%	4.35%	4.45%	102.24%	3.93%	8.37%
6	Xcel Energy, Inc.	3.68%	4.68%	4.35%	4.61%	102.34%	3.77%	8.38%
7	SCANA Corp.	3.90%	4.45%	4.35%	4.43%	102.23%	3.99%	8.42%
8	PPL Corp.	4.67%	3.74%	4.35%	3.86%	101.87%	4.76%	8.62%
9	Great Plains Energy	3.83%	4.80%	4.35%	4.71%	102.40%	3.92%	8.63%
10	DTE Energy Co.	3.75%	5.00%	4.35%	4.87%	102.50%	3.84%	8.71%
11	Pinnacle West Capital Corp.	3.92%	4.95%	4.35%	4.83%	102.48%	4.02%	8.85%
12	Avista Corp.	3.98%	5.00%	4.35%	4.87%	102.50%	4.08%	8.95%
13	Dominion Resources, Inc.	3.72%	5.49%	4.35%	5.26%	102.75%	3.82%	9.08%
14	PG&E Corp.	3.50%	5.80%	4.35%	5.51%	102.90%	3.60%	9.11%
15	Alliant Energy	3.72%	5.55%	4.35%	5.31%	102.78%	3.82%	9.13%
16	ALLETE, Inc.	4.16%	5.00%	4.35%	4.87%	102.50%	4.26%	9.13%
17	Eversource Energy	3.39%	6.57%	4.35%	6.13%	103.29%	3.50%	9.63%
18	CMS Energy Corp.	3.36%	6.72%	4.35%	6.25%	103.36%	3.47%	9.72%
19	Ameren Corporation	3.96%	6.00%	4.35%	5.67%	103.00%	4.08%	9.75%
20	El Paso Elec. Co.	3.20%	7.00%	4.35%	6.47%	103.50%	3.31%	9.78%
21	Otter Tail Corp.	4.05%	6.00%	4.35%	5.67%	103.00%	4.17%	9.84%
22	NorthWestern Corp.	3.61%	6.81%	4.35%	6.32%	103.41%	3.73%	10.05%
23	WEC Energy Group, Inc.	3.58%	7.55%	4.35%	6.91%	103.78%	3.72%	10.63%
24	Sempra Energy	2.84%	9.35%	4.35%	8.35%	104.68%	2.97%	11.32%
25	PNM Resources, Inc.	2.92%	9.30%	4.35%	8.31%	104.65%	3.06%	11.37%
27	IDACORP, Inc.	3.03%	4.00%	4.35%	4.07%	102.00%	3.09%	7.16%
26	CenterPoint Energy, Inc.	5.47%	0.40%	4.35%	1.19%	100.20%	5.48%	6.67%
28	OGE Energy Corp.	3.81%	2.17%	4.35%	2.61%	101.09%	3.85%	6.46%
29	Public Service Enterprise Group	3.85%	1.38%	4.35%	1.97%	100.69%	3.88%	6.28%

30	FirstEnergy Corp.	4.51%	-0.92%	4.35%	0.13%	99.54%	4.49%	5.38%
31	Edison International	2.85%	-0.51%	4.35%	0.46%	99.75%	2.84%	3.92%
32	Black Hills Corp.	Merger						
33	Cleco Corp.	Merger						
34	Duke Enegy Corp.	Merger						
35	Empire District	Merger						
36	Exelon Corp.	Merger						
37	Hawaii Elec. Ind. Inc.	Merger						
38	ITC Holdings	Merger						
39	NextEra Energy Inc.	Merger						
40	Pepco Holdings Inc.	Merger						
41	Souther Co.	Merger						
42	TECO Energy Inc.	Merger						
43	UIL Energy	Merger						

Moodys Baa Utility Bonds	5.41%
Low With Outlier Test	7.37%
High	11.37%
Midpoint	9.37%
High-End Outlier Test	17.43%
Low-End Outlier Test	7.18%

Appendix III: Overall Results

MISO I	Zone of Reasonableness		Lower Third		Middle Third		Upper Third	
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
DCF (1)	6.97%	12.07%	6.97%	8.67%	8.67%	10.37%	10.37%	12.07%
CAPM (2)	7.80%	13.09%	7.80%	9.56%	9.56%	11.33%	11.33%	13.09%
Risk Premium (3)	7.50%	12.70%	7.50%	9.23%	9.23%	10.97%	10.97%	12.70%
Average	7.42%	12.62%	7.42%	9.16%	9.16%	10.89%	10.89%	12.62%
Midpoint	**10.02%**							
Average Width of DCF and CAPM Zones of Reasonableness:					5.195			
Risk Premium ROE:		10.10%						
Risk Premium Imputed Zone of Reasonableness:					7.50%	to	12.70%	

MISO II	Zone of Reasonableness		Lower Third		Middle Third		Upper Third	
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
DCF (4)	7.37%	11.37%	7.37%	8.70%	8.70%	10.04%	10.04%	11.37%
CAPM (5)	8.35%	12.63%	8.35%	9.78%	9.78%	11.20%	11.20%	12.63%
Risk Premium (6)	8.22%	12.36%	8.22%	9.60%	9.60%	10.98%	10.98%	12.36%
Average	7.98%	12.12%	7.98%	9.36%	9.36%	10.74%	10.74%	12.12%
Midpoint	**10.05%**							
Average Width of DCF and CAPM Zones of Reasonableness:					4.14			
Risk Premium ROE:		10.29%						
Risk Premium Imputed Zone of Reasonableness:					8.23%	to	12.37%	

(1) See Appendix II
(2) See Trial Staff Initial Br. (I), Attachment A to App. 2 at 6.
(3) See Appendix I
(4) See Appendix II
(5) See Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.
(6) See Appendix I

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Association of Businesses Advocating Tariff Equity Docket No. EL14-12-004
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation Docket No. EL15-45-001
Mississippi Delta Energy Agency
Clarksdale Public Utilities Commission
Public Service Commission of Yazoo City
Hoosier Energy Rural Electric Cooperative, Inc.

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
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Entergy Arkansas, Inc.
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Otter Tail Power Company
Southern Indiana Gas & Electric Company

(Issued May 21, 2020)

GLICK, Commissioner, *concurring in part and dissenting in part*:

1. Today's order is yet another twist in the Commission's decade-long effort to adapt its methodology for setting public utilities' return on equity (ROE) to the low-interest rate conditions that have prevailed since the late 2000s. In that time, the Commission has proposed multiple different ways of dealing with the fact that its long-standing ROE methodology produces cost-of-equity estimates well below the ROEs it generally permitted public utilities to collect in the years before the Great Recession. The

Commission's most recent attempt to address this issue, Opinion No. 569,[1] was far from perfect. Nevertheless, I supported it because it represented a reasonable compromise that I hoped would bring some much-needed certainty and predictability to the Commission's approach to setting public utilities' ROEs.

2. So much for that. Today, we are once again changing course and revamping our ROE methodology. And, in so doing, we are sacrificing whatever certainty Opinion No. 569 might have provided.

3. In addition, I am particularly troubled that the Commission is portraying its change of heart as a dispassionate assessment of various technical questions—the comparative merits of one financial model, the right source of data for another, or the appropriate application of various assumptions. It is hard for me to believe that anyone buys that this latest twist is a genuine reassessment of those technical minutiae or that those details are what led Chairman Chatterjee to express his eagerness to consider rehearing requests at the December 2019 Open Meeting, before those requests were even filed. Instead, it appears that the Commission again has chosen a path directed by the results, in this case the perceived need to award a higher ROE, rather than the law and the facts.

4. In fairness, it may be that the methodology established in Opinion No. 569 would yield ROEs that are too low. And it may also be that the ROE established in this proceeding—10.02 percent—is a just and reasonable number. But, even so, the Commission must be transparent about the factors driving its decisionmaking process. If we think the ROEs set by the Commission's methodology are too low—or, for that matter, too high—we ought to say so and explain our reasoning, rather than pretending to be concerned only with the technical details of our models, data, and assumptions. Accordingly, I dissent in part because I do not believe that today's order adequately justifies several of the changes it adopts, even if the end result is an appropriate number.

5. Finally, today's order affirms the one aspect of Opinion No. 569 that merited a grant of rehearing. Opinion No. 569 declined to order refunds for a period in which everyone agrees customers paid an unjust and unreasonable rate. I continue to believe that decision was an abdication of our responsibility to protect consumers. As a result, I also dissent from the portion of today's order that affirms that decision.

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[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019).

I. The Commission Must Stop the Endless Fiddling with Its ROE Methodology

6. Between 2011 and 2015, various entities representing customers' interests filed a series of complaints under section 206 of the Federal Power Act[2] (FPA) arguing that the base ROE available to transmission owners in ISO New England, Inc. and the Midcontinent Independent System Operator (MISO) was unjust and unreasonable. In Opinion No. 531, the Commission addressed the first of those complaints, with its most significant findings being that "anomalous capital market conditions" required the Commission to consider a variety of financial models and that those models supported an elevated ROE.[3] The Commission subsequently applied that approach to a similar complaint involving the MISO Transmission Owners.[4] Shortly thereafter, however, the D.C. Circuit vacated Opinion No. 531, sending it back to the Commission and the Commission back to the drawing board.[5] Following that remand, the Commission proposed to expressly rely on the four financial models considered in Opinion No. 531.[6] A year later, in Opinion No. 569, we narrowed it to two models, while making a number of changes to how we implemented those models.[7] Today, we're back up to three models, with another round of tweaks to those models.[8]

7. With the exception of the Commission's finding of anomalous market conditions, which at least hinted at its real concern, the Commission's various orders in this saga have suggested that each new iteration of its ROE methodology is a largely technical affair that turns on the Commission's evaluation of discrete issues with the various

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[2] 16 U.S.C. ¶ 824e (2018).

[3] *Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co*., Opinion No. 531, 147 FERC ¶ 61,234, at PP 41, 152 (2014).

[4] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016).

[5] *Emera Maine v. FERC*, 854 F.3d 9 (2017).

[6] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (Briefing Order).

[7] Opinion No. 569, 169 FERC ¶ 61,129.

[8] Although the complaints against the RTO-wide ROEs in MISO and ISO New England garnered the most attention, the last ten years have also seen a host of other complaints against individual transmission owner's ROEs, which have also been affected by the Commission's back-and-forth over these complaints.

financial models. In so doing, the Commission has added new models,[9] removed some of those models,[10] tweaked some of those models,[11] introduced new inputs,[12] modified existing inputs,[13] introduced new screens,[14] modified existing screens,[15] and even altered how the Commission places the ROE within the zone of reasonableness.[16] But, with each

[9] *See, e.g.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 9 (relying on four alternative models to place the ROE within the zone of reasonableness).

[10] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 200, 340 (declining to rely on the Expected Earnings or Risk Premium methodologies). Indeed, at this point, the Commission has considered, but not relied on the risk premium model, Opinion No. 551, 156 FERC ¶ 61,234 at P 191, proposed relying on the risk premium model, Briefing Order, 165 FERC ¶ 61,118 at PP 18-19**,** declined to rely on the risk premium model, Opinion No. 569, 169 FERC ¶ 61,129 at P 340, and, with today's order, now elected to rely on the rely risk premium model, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 171 FERC ¶ 61,154, at P 104 (2020).

[11] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 107 (modifying the risk premium model to produce a zone of reasonableness rather than a single point estimate).

[12] *Compare* Opinion No. 569, 169 FERC ¶ 61,129 at P 274 (rejecting the use of *Value Line* short-term growth rates in the Capital Asset Pricing Model (CAPM)) *with* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 78 ("clarify[ing]" that the Commission will consider *Value Line* short-term growth rates in the CAPM).

[13] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 57 (reducing the weighting of the long-term growth rate in the two-step Discounted Cash Flow model (DCF) from one-third to one-fifth).

[14] Briefing Order, 165 FERC ¶ 61,118 at P 54 (proposing a high-end outlier screen that would apply to "any proxy company whose cost of equity estimated with a given model is more than 150 percent of the median result of all of the potential proxy group members in that model"); Opinion No. 569, 169 FERC ¶ 61,129 at P 375 (adopting the proposed high-end outlier screen).

[15] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 154 (increasing the threshold for the high-end outlier test from 150 percent of the median of the zone of reasonableness to 200 percent of the median of the zone of reasonableness).

[16] *See, e.g.*, *id.* P 193 (changing the start points for setting ROEs for above- and below-average ROEs); Opinion No. 551, 156 FERC ¶ 61,234 at P 275 (setting the MISO-wide ROE at the midpoint of the upper half of the zone of reasonableness).

new twist, it becomes harder to buy that the Commission is genuinely reassessing the mechanics of each model rather than disagreeing with the ROE numbers those models produce.[17]

8. Today's order is the culmination of all that. Not long after completing a year-long process to re-evaluate our approach to setting ROEs following the D.C. Circuit's decision in *Emera Maine*, the Commission is now once again charting a major change of course. In so doing, the Commission is again portraying its change of heart as a technical matter based on its reassessment of a handful of discrete issues rather than what it is: A determination that the old number was too low and now we need a higher one.

9. To be fair, I am sympathetic to the impulse to consider subjective factors. The Commission's approach to setting a just and reasonable ROE will often implicate broader policy considerations, equity, and other factors that cannot be captured in, for example, a discussion of dividend yields or the appropriate sources of growth rate calculations. But while ROE policy will always be as much art as science, that is no excuse to pretend that art is science.

10. If broader considerations, including policy goals, are preventing the Commission from settling on or consistently applying an ROE methodology, then we must acknowledge those goals and give the interested entities the chance to weigh in on them just as they do for the intricacies of dividend yields, growth rates, and the like. All approaches to setting ROEs have their shortcomings, but the worst result by far is to continually fiddle with those approaches, undermining the certainty and predictability that help transmission owners make long-term investments. If the Commission is going to purport to rely entirely on financial models to evaluate and set ROEs, it has to take those models at face value without second-guessing them when it does not like the results.

11. In addition, today's order illustrates the problems with disguising subjective policy considerations as technical determinations. In a number of instances, the Commission is reversing determinations made in Opinion No. 569 using rationales that are far less convincing than those that supported the opposite outcome in Opinion No. 569. Shifting

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[17] It is also worth noting that, today, the Commission is adding even more complexity to its approach to setting ROE methodologies by also issuing a policy statement regarding oil and natural gas pipelines that largely follows the approach outlined in Opinion No. 569 rather than this order. In particular, that policy statement does not use the risk premium model, adjust the weighting of long- and short-term growth rates for the two-step DCF model, or adopt a particular high-end outlier screen. *See Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*, 171 FERC ¶ 61,155 at PP 2, 87 (2020). The Commission, it seems, just cannot settle on an analytically consistent approach to this important issue.

from such strong arguments to such suspect ones underscores the extent to which subjective factors seem to be operating in the background while also opening the Commission up to considerable risk on judicial review, creating even more of the uncertainty we ought to be trying to minimize.

12. Take the example of the risk premium model. Although Opinion No. 569 declined to utilize the risk premium model based on a long list of shortcomings, today's order reverses course, adding it to the DCF and CAPM on which the Commission previously relied. The record before us does not support that choice.

13. As an initial matter, and as explained in Opinion No. 569, the risk premium model does essentially the same thing as the CAPM by attempting to calculate the "premium that investors require over the risk-free rate of return."[18] Opinion No. 569 rightly pointed out that nothing in the record supports having two thirds of the Commission's ROE methodology composed of such analytically redundant approaches.[19] Today's order tersely responds to that concern by asserting that the two models are "sufficiently distinct" since they use different inputs.[20] But that ignores the point in Opinion No. 569 that the problem with relying on both models is that they replicate the same basic methodology, irrespective of their inputs.[21]

14. Opinion No. 569 also explained how the risk premium model is, in most respects, just an inferior version of the CAPM in so far as it does not consider market-based cost-of-equity estimates[22] and introduces significant circularity concerns by relying on *past*

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[18] Opinion No. 569, 169 FERC ¶ 61,129 at P 341.

[19] *Id.*

[20] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 105.

[21] Opinion No. 569, 169 FERC ¶ 61,129 at P 341 ("We find that using the Risk Premium model in conjunction with the CAPM model would confer too much weight towards risk premium methodologies. The Commission has long used and, over time, refined the DCF model and we find that it would be inappropriate for variations of the risk premium model to receive twice its weight.").

[22] *Id.* P 342 ("[T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data."). In addition, as the Commission noted, many of the ROEs included in the risk premium analyses in the record were never determined to be just and reasonable. For example, many of the ROEs were set through uncontested settlements, which involve compromise across a host of issues of which ROE is just one.

judgments, which may not reflect the appropriate risk premium under current conditions.[23] The Commission responds to those circularity concerns by contending that they are "mitigate[d]" by the fact that the Commission will average the results of the risk premium with the DCF and the CAPM, which do not present the same concerns.[24] But observing that the Commission will *also* use models without significant circularity concerns is not a reasoned response to the argument that you should not use circular models in the first place.

15. In addition, the Commission convincingly explained in Opinion No. 569 how "the record contains insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions."[25] The Commission noted that, while allowed ROEs are certainly important to investors' decisionmaking, that does not suggest that investors' perform anything remotely close to the analysis contemplated by the risk premium model—*i.e.*, a backward looking comparison between riskless assets and allowed ROEs—when making their investment decisions.[26] Today's order now takes the opposite position, observing only that investors in regulated utilities expect to earn a return above a risk-free asset (which is obviously true) and that "investors . . . observe regulatory ROEs and how changes in authorized ROE levels could affect utility earnings" (which is equally obvious).[27] It should go without saying that investors pay attention to ROEs earned by public utilities and expect them to be higher than debt backed by the U.S. government. But neither of those self-evident statements provides *any* reason—much less substantial evidence—to believe that investors perform a risk premium analysis comparing past differences between risk free assets and Commission-allowed ROEs when evaluating whether to invest in Commission-regulated public utilities.

16. And, finally, the risk premium model does not at all fit with the Commission's new approach for evaluating whether an existing ROE is just and reasonable. Opinion No. 569 established a framework for evaluating whether an existing ROE is just and

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The Commission frequently approves uncontested without directly passing on whether the individual terms are just and reasonable. *See id.*

[23] *See id.* P 343 (explaining that the circularity concerns with the risk premium model are "particularly direct and acute").

[24] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 106.

[25] Opinion No. 569, 169 FERC ¶ 61,129 at P 345.

[26] *Id.*

[27] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 112.

reasonable based on ranges of presumptively just and reasonable results derived from the financial models used by the Commission.[28] Unlike every other financial model used, or even considered by the Commission in Opinion No. 569,[29] the risk premium model produces a single point estimate of the just and reasonable ROE, not a zone of reasonableness.[30]

17. Recognizing this "serious concern," but nevertheless determined to fit a square peg into a round hole, today's order resolves to "impute" the average width of the zone of reasonableness created by the DCF and CAPM methodologies to the risk premium model.[31] For example, if the DCF and CAPM produce an average zone of 200 basis points, it seems that the Commission will just assume that the risk premium model does too. Today's order, however, does not point to any evidence suggesting that such imputation is appropriate or that any investors or financial experts have sanctioned the Commission's method. Presumably that is because the record lacks any evidence supporting such an odd repurposing of the risk premium model.[32] After all, the Commission's approach to using the risk premium in evaluating whether an existing ROE is just and reasonable is the equivalent of making someone a "custom" suit based on their siblings' measurements: Maybe it will fit, but there is no reason to believe that it will and, in any case, it misses the point of the exercise.

18. In addition, today's order adopts a series of equally unreasoned modifications to Opinion No. 569's framework for conducting the first step of the section 206 inquiry. As noted, Opinion No. 569 established a practice of dividing the zone of reasonableness into ranges of presumptively just and reasonable ROEs within the broader zone of reasonableness.[33] In particular, the Commission created risk-adjusted "quartiles" of the

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[28] Opinion No. 569, 169 FERC ¶ 61,129 at P 57.

[29] The Commission also considered, but rejected, relying upon an expected earnings model as well. *Id.* P 200.

[30] *Id.* P 351.

[31] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 107.

[32] That become especially clear when compared with the Commission's thorough and well-reasoned rejection of the risk premium on this basis, among others, in Opinion No. 569. *Compare id* P 107 *with* Opinion No. 569, 169 FERC ¶ 61,129 at P 351.

[33] That change responded to the D.C. Circuit's holding that the FPA contemplates "a 'broad' range of potentially just and reasonable ROEs, 'not an exact dollar figure.'" *Emera Maine v. FERC*, 854 F.3d 9, 23 (D.C. Cir. 2017) (quoting *Panhandle E. Pipe Line Co. v. FERC*, 777 F.2d 739, 746 (D.C. Cir. 1985)).

zone of reasonableness centered on the three points that the Commission uses as the starting point for setting ROEs for utilities of different risk profiles[34]—the midpoint of the entire zone of reasonableness for average-risk utilities, the midpoint of the lower half of the zone of reasonableness for below-average risk utilities, and the midpoint of the upper half of the zone of reasonableness for above-average risk utilities.[35]

19. The Commission justified the end points of each quartile by explaining that "[l]ogic dictates that the end points of those ranges should not be closer to the starting points for the ranges of utilities with different risk profiles than they are to their own starting point."[36] In other words, it would not make sense to presume that an existing ROE is just and reasonable if it was closer to the starting point used to set the ROE for a utility of a different risk profile than the starting point for a utility of the same risk profile. The Commission's quartile-based approach made sense given the emphasis that the Commission has historically placed on relative risk profiles when placing ROEs within the zone of reasonableness[37] and it ensured that the ranges of presumptively just and reasonable results were not just arbitrary sub-sections of the zone of reasonableness.

20. Today's order abandons that well-reasoned approach and arbitrarily divides the entire zone of reasonableness into thirds, with each third providing a presumptively just and reasonable range of ROEs for certain utilities. The Commission appears to suggest[38] that this maneuver is necessary to comply with the D.C. Circuit's statement in *Emera Maine* that "the zone of reasonableness creates a broad range of *potentially* lawful

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[34] Opinion No. 569, 169 FERC ¶ 61,129 at P 57.

[35] *Id*. The midpoint is the measure of central tendency that the Commission uses when setting the ROE for a diverse range of utilities. *Id.* PP 398, 409. By contrast, the Commission uses the median as the measure of central tendency when setting the ROE for a single utility. *Id.* P 398.

[36] *Id.* P 63.

[37] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 62 ("We also find that the circumstance most relevant to determining that range is the utility's risk profile."); *see also FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 6-99700 (D.C. Cir. 2007) (explaining the emphasis that the Commission and courts have placed on the role of risk in setting ROEs).

[38] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 190.

ROEs."[39] But *Emera Maine* requires nothing of the sort. Read in context, the quoted language stands only for the proposition that the Commission cannot prove that an existing rate is unjust and unreasonable simply by showing that its ROE methodology would produce a different number using current data.[40] The court certainly did not suggest that every point within the zone of reasonableness must be *presumptively* just and reasonable for some utility, which is how today's order appears to understand that language. In any case, the quartile-based approach in Opinion No. 569 easily complied with even the Commission's reading of the language in *Emera Maine*. Because the ranges only represented presumptive findings, a public utility could still argue that an ROE outside those ranges was nevertheless just and reasonable based on other considerations,[41] making every ROE within the zone of reasonableness at least "potentially" just and reasonable.

21. And that's just the start of it. Recognizing that the decision to divide the zone of reasonableness into thirds obliterates the rationale for the ranges outlined in Opinion No. 569,[42] the Commission announces, without any explanation, that it will change the starting points it uses when setting the ROE for below- and above-average risk utilities to the midpoint of the lower third of the zone of reasonableness and the midpoint of the upper third of the zone of reasonableness, respectively.[43] Now the tail is truly wagging the dog. In Opinion No. 569, the Commission justified the ranges of presumptively just and reasonable ROEs based on the Commission's longstanding approach to handling companies' relative risk profiles, namely the use of the upper and lower midpoints for utilities of above- and below-average risk, respectively.[44] In today's order, the Commission uproots that longstanding approach, selecting entirely new starting points for placing ROEs within the zone of reasonableness in order to support its new ranges of

[39] *Emera Maine*, 854 F.3d at 26 (emphasis added).

[40] *Id.* ("But, as we have explained, the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE, meaning that FERC's finding that 10.57 percent was a just and reasonable ROE, standing alone, did not amount to a finding that every other rate of return was not." (internal quotation marks omitted)).

[41] Opinion No. 569, 169 FERC ¶ 61,129 at PP 60-64, 68 (discussing how the Commission would apply the new framework, including what other factors it would consider).

[42] *See supra* P 20 & note 37.

[43] Opinion No. 569-A, 171 FERC ¶ 61,154 at 194.

[44] Opinion No. 569, 169 FERC ¶ 61,129 at PP 62-64.

presumptively just and reasonable results. That gets it entirely backwards; the ranges of presumptively just and reasonable results should reflect how we set ROEs, not the other way around. In any case, at no point in today's order does the Commission explain why the new starting points themselves are an appropriate place to begin the process of placing the ROE for an above- or below-average risk utility within the zone of reasonableness.[45]

22. Suffice it to say, the Commission has not justified its change of course with respect to either the risk premium model or its approach to step one of the section 206 inquiry. Nevertheless, while I believe that Opinion No. 569 was a superior approach to setting ROEs, I also recognize that the roughly 10 percent ROE established in today's order may well be a just and reasonable end result.[46] In addition, for the reasons explained above, I firmly believe that the Commission must finally bring some certainty and predictability to how its sets transmission owner ROEs.

II. The Commission Should Order Refunds for Unjust and Unreasonable Rates Paid by Consumers

23. I continue to disagree with the Commission's refusal to order refunds for the fifteen-month refund period established pursuant to the Second Complaint.[47] Throughout that period, customers within MISO paid an unjust and unreasonable ROE. Nevertheless, the Commission refuses to order refunds on the specious basis that the FPA requires it to act as if the 10.02 percent ROE set in today's order was in effect throughout that fifteen-month period. In reality, however, customers actually paid a 12.38 percent ROE—a difference worth tens of millions of dollars—and nothing in the law requires us to pretend otherwise.

24. The facts relevant to the issue of refunds are straightforward. On November 12, 2013, multiple parties filed a complaint (First Complaint) alleging that the MISO Transmission Owners' 12.38 percent ROE was unjust and unreasonable.[48] The

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[45] That failure is particularly glaring because the new starting points will be closer to either the top or bottom of the zone of reasonableness than the midpoint. Nothing in today's order—or the record before us—explains why those starting points should be biased towards the most extreme costs of equity in the zone of reasonableness.

[46] *Cf. Hope*, 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.").

[47] *See* Opinion No. 569, 169 FERC ¶ 61,129 (Glick, Comm'r, dissenting in part).

[48] *Id.* P 3. The authorized base ROE for the ATCLLC zone was 12.20 percent, but I will follow the underlying order's practice of referring to the MISO-wide ROE as 12.38.

Commission set the matter for hearing and established a refund effective date of November 12, 2013 (the date the First Complaint was filed),[49] meaning that the 15-month refund period for the First Complaint lasted until February 12, 2015.[50] On February 12, 2015, a different set of parties filed another complaint (Second Complaint) against the MISO Transmission Owners' ROE. The Commission again set the matter for hearing and established a refund effective date of February 12, 2015,[51] meaning that the 15-month refund period for the Second Complaint lasted until May 12, 2016. Both proceedings were fully litigated and produced initial decisions by Administrative Law Judges.[52] And, in both cases, the Commission did not get around to issuing orders on the initial decisions until well after both refund periods expired, meaning that customers paid rates reflecting a 12.38 percent ROE throughout both refund periods.[53]

25. In today's order, the Commission affirms its conclusion in Opinion No. 569 that the 12.38 percent ROE was unjust and unreasonable and it establishes a new just and reasonable ROE of 10.02 percent. That is sufficient to order refunds for the refund

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Id. P 3 & n.11.

[49] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014), *order on reh'g*, 156 FERC ¶ 61,060 (2016).

[50] As discussed further below, pursuant to the Regulatory Fairness Act, Pub. L. No. 100-473, § 2, 102 Stat 2299 (1988) (codified at 16 U.S.C. § 824e(b)), as part of any proceeding under section 206 of the FPA, the Commission shall establish a refund effective date and, at the conclusion of that proceeding, it may order refunds for the difference between an unjust and unreasonable rate in effect during the period up to 15 months following the refund effective date and the new just and reasonable rate fixed by the Commission.

[51] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (Second Complaint Rehearing Order).

[52] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015); *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016).

[53] The Commission originally issued an order on the First Complaint in September 2016. *See Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234, at P 9 (2016). But, shortly thereafter, the D.C. Circuit issued its opinion in *Emera Maine*, 854 F.3d 9, which vacated the precedent on which Opinion No. 551 relied. Following briefing on remand, the Commission issued Opinion No. 569, which elicited the rehearing requests addressed in today's order.

periods established pursuant to *both* the First and Second Complaints. To see why, let's start with the text of section 206(b), which provides that

> At the conclusion of any proceeding under this section [i.e., section 206], the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force.[54]

All that text requires is that the Commission find that customers paid an unjust and unreasonable rate during the refund period and that the Commission have set a just and reasonable replacement rate, so that it can calculate refunds equal to the difference between those two rates. Both conditions are satisfied here: Customers paid 12.38 percent through the Second Complaint refund period and the Commission has determined that they should have paid 10.02 percent. That is sufficient to order refunds pursuant to section 206(b).

26. Contrary to the suggestion in today's order,[55] the text of section 206(b) does not limit the Commission's refund authority to only those individual proceedings in which it sets a new rate. Instead, it provides the Commission with the authority to order refunds "[a]t the *conclusion* of *any* proceeding under this section"—*i.e.*, section 206."[56] Congress surely understood that not every section 206 proceeding would be resolved against the public utility and, had it so desired, it could have conditioned the Commission's refund authority accordingly. But by pairing the word "conclusion"—which would seem to contemplate proceedings in which the public utility prevailed as well as those in which it did not—with the phrase "any proceeding"—which is equally unlimited—Congress rejected such a narrow interpretation of the Commission's refund authority. Instead, as noted, the plain text of section 206 indicates that the Commission's refund authority turns on the presence of a difference between the unjust and unreasonable rate that customers paid during the refund period and the just and reasonable rate that they should have paid, not whether the Commission set a new rate in every complaint it resolves.

27. Recognizing that Congress did not explicitly limit the Commission's refund authority, the Commission responds that it did so implicitly when it inserted the phrase

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[54] 16 U.S.C. § 824e(b) (emphasis added).

[55] Opinion No. 569-A, 171 FERC ¶ 61,154 at PP 260-262.

[56] 16 U.S.C. § 824e(b) (emphasis added).

"thereafter observed and in force" in section 206(b).[57] The idea, as I understand it, is that "thereafter observed and in force" is supposed to reflect Congress' understanding that the Commission would be setting a new rate in each complaint prior to ordering any refunds.[58] Thus, the argument appears to go, the Commission cannot order refunds unless it sets a new rate in the complaint corresponding to each individual refund period.

28. As an initial matter, that would be a remarkably convoluted way of limiting the Commission's refund authority under section 206. It envisions that, instead of limiting the Commission's refund authority in the statutory text that establishes the proceedings in which the Commission can order refunds, Congress elected to do so through an opaque reference in the discussion of how the Commission should calculate any refunds that it may order. That is a bizarre—and overly complicated—way to read an otherwise straightforward statute.[59]

29. In any case, the "thereafter observed and in force" language is better read as a reference to the identical language in section 206(a).[60] Under that reading, all that "thereafter observed and in force" does is clarify that the ceiling on the Commission's refund authority under section 206(b) is the difference between the rate in effect during the refund period and the just and reasonable rate that the Commission established pursuant to subsection 206(a).[61] In other words, that language specifies *how* the Commission should calculate any refunds it orders, not *when* it may order refunds. As noted, my reading makes far more sense given the fact that the "thereafter observed and in force" language appears in the portion of 206(b) that defines how the Commission should calculate refunds, not when it should order them. I see no reason to abandon that

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[57] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 262.

[58] *Id.*

[59] *Cf. City of Anaheim v. FERC*, 558 F.3d 521, 525 (D.C. Cir. 2009) ("declin[ing] FERC's invitation to mangle the statute").

[60] *See* 16 U.S.C. § 824e(a) (requiring the Commission to establish a new just and reasonable rate to be "thereafter observed and in force" whenever it finds that an existing rate is unjust and unreasonable or unduly discriminatory or preferential).

[61] That interpretation makes even more sense when you consider that section 206(b) was added more than 50 years after section 206(a), which was part of the original FPA, and so it would have been necessary to clarify how the amendment worked in conjunction with the pre-existing language.

straightforward reading of the statute, which protects customers from paying unjust and unreasonable rates, in favor of a convoluted one that does not.[62]

30. The Commission's next argument is even more of a head scratcher. The Louisiana Public Service Commission argues that it is irrational to use the ROE set in Opinion No. 569 as the baseline for evaluating whether to order refunds for the Second Complaint refund period because that ROE was never "demanded, observed, charged, or collected," as section 206 requires. The Commission responds with what might charitably be called a regulatory fiction. It argues that Opinion No. 569 made the new just and reasonable ROE set in the First Complaint proceeding effective as of the beginning of the First Complaint refund period, which, the Commission argues, means that we must pretend that that lower ROE was in effect throughout the refund period for the Second Complaint as well. The Commission seems to be suggesting that it must pretend that the 10.02 ROE established today was "demanded, observed, charged, or collected" during the second refund period.[63]

31. But that interpretation is both demonstrably false and squarely foreclosed by section 206. First and foremost, the ROE that the MISO Transmission Owners collected during the refund period for the Second Complaint was 12.38 percent, no ifs, ands, or buts. In addition, the FPA flatly prohibited the MISO Transmission Owners from collecting any other ROE during that period. As noted, section 206 is forward looking in that it gives the Commission the ability to set a new just and reasonable rate as of the date on which the Commission makes the findings required by section 206.[64] The only exception to that rule is for the refund period, during which time the Commission is

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[62] *Cf., e.g.*, *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (9th Cir. 2004) (rejecting "an interpretation [that] comports neither with the statutory text nor with the Act's 'primary purpose' of protecting consumers"); *City of Chicago, Ill. v. FPC*, 458 F.2d 731, 751 (D.C. Cir. 1971) ("[T]he primary purpose of the Natural Gas Act is to protect consumers." (citing, *inter alia*, *City of Detroit v. FPC*, 230 F.2d 810, 815 (D.C. Cir. 1955)); S. Rep. 100-491, 5-6 (1988) ("The Committee intends the Commission to exercise its refund authority under section 206 in a manner that furthers the long-term objective of achieving the lowest cost for consumers consistent with the maintenance of safe and reliable service.").

[63] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 264.

[64] *See, e.g.*, *Louisiana Pub. Serv. Comm'n v. FERC*, 772 F.3d 1297, 1299 (D.C. Cir. 2014) (explaining that section 206 provides for prospective relief only with the exception of the refund period).

permitted to act as if the new rate were in effect when ordering refunds.[65] The refund period for the Second Complaint, however, fell *after* the conclusion of the refund period for the First Complaint and *before* the date on which the Commission issued Opinion No. 569. Suffice it to say, it is arbitrary and capricious for the Commission to assume that it did that which it is legally prohibited from doing.

32. The Commission's next argument is that ordering refunds for the Second Complaint would represent an end-run around the 15-month limitation on refunds enshrined in section 206(b).[66] That argument appears to have both a legal dimension and a policy dimension. Beginning with the former, the Commission seems to be taking the position that ordering refunds in the Second Complaint period would effectively extend the refund period established for the First Complaint. But the Commission has repeatedly held that the FPA permits such successive or "pancaked" complaints, which are "'entirely new proceeding[s]'" and not "'duplicative proceeding[s] intended solely to expand the amount of refund protection beyond 15 months,'"[67] provided that they raise new facts or arguments,[68] which the Commission held that the Second Complaint did.[69] Accordingly, rather than extending the refund period for the First Complaint, ordering refunds pursuant to the Second Complaint would simply reflect the fact that the MISO Transmission Owners collected an unjust and unreasonable ROE during a period when all parties were on notice that the Commission might order refunds of such excessive rates.[70]

33. From the perspective of public policy, I recognize that permitting pancaked complaints with multiple refund periods may be sub-optimal. After all, pancaked complaints can create significant uncertainty in an area where certainty is especially

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[65] *Id.*

[66] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 259.

[67] Second Complaint Rehearing Order, 156 FERC ¶ 61,061 at P 33 (quoting *Southern Co. Servs. Inc*., 83 FERC ¶ 61,079, 61,386 (1998)).

[68] *Id.* P 33 ("[T]he Commission has allowed multiple complaints regarding the same ROE, where the subsequent complaints are based on new, more current data, explaining that this is particularly critical given that what is at issue is return on equity, which, in contrast to other cost of service issues can be particularly volatile. (internal alterations and quotation marks omitted)).

[69] *Id.* P 34.

[70] *Cf. La. Pub. Serv. Comm'n v. FERC*, 482 F.3d 510, 520 (D.C. Cir. 2007) (noting that the filing of a section 206 put all parties on notice of the possibility that the Commission would order refunds).

important as transmission owners decide whether and how to invest in transmission infrastructure. But the desirability of pancaked complaints is something for Congress to consider, not a reason for us to twist the text of the FPA. So long as the FPA and the Commission's precedents permit pancaked complaints, then the Commission should not let its antipathy toward such complaints prevent customers from receiving the refunds to which they are entitled.

For these reasons, I respectfully concur in part and dissent in part.

_____

Richard Glick
Commissioner

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Atmos Energy Corporation (ATO)

(Delayed Data from NYSE)

$101.68 USD

+2.50 (2.52%)

Updated May 28, 2020 04:00 PM ET

Pre-Market: **$101.68** 0.00 (0.00%) 7:57 PM ET

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Industry Rank:

Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

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Detailed Estimates

Estimates	
Next Report Date	8/5/20
Current Quarter	0.78
EPS Last Quarter	1.95
Last EPS Surprise	0.52%
ABR	1.75
Earnings ESP	-1.06%
Current Year	4.70
Next Year	5.03
EPS (TTM)	4.59
P/E (F1)	21.63

Growth Estimates	ATO	IND	S&P
Current Qtr (06/2020)	14.71	17.86	-4.48
Next Qtr (09/2020)	10.20	-50.78	-50.17
Current Year (09/2020)	8.05	0.10	NA
Next Year (09/2021)	7.02	9.30	-4.94
Past 5 Years	8.80	2.30	NA
Next 5 Years	7.20	6.30	NA
PE	21.63	4.10	18.26
PEG Ratio	3.00	0.65	NA

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Premium Research for ATO

Zacks Rank	▲ Buy 2
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	B Value | C Growth | A Momentum | B VGM
Earnings ESP	-1.06%
Research Reports for ATO	Analyst | Snapshot

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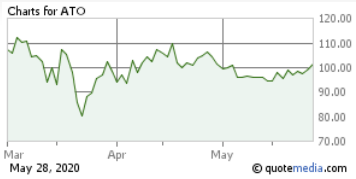

Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	622.02M	581.70M	3.20B	3.53B
# of Estimates	1	1	2	2
High Estimate	622.02M	581.70M	3.35B	3.64B
Low Estimate	622.02M	581.70M	3.06B	3.42B
Year ago Sales	485.74M	443.68M	2.90B	3.20B
Year over Year Growth Est.	28.06%	31.11%	10.36%	10.17%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	0.78	0.54	4.70	5.03
# of Estimates	3	2	4	4
Most Recent Consensus	NA	NA	NA	NA
High Estimate	0.80	0.56	4.72	5.06

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Low Estimate	0.77	0.52	4.68	5.00
Year ago EPS	0.68	0.49	4.35	4.70
Year over Year Growth Est.	14.71%	10.20%	8.05%	7.02%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Up Last 7 Days	1	0	1	1
Up Last 30 Days	1	0	1	1
Up Last 60 Days	1	0	0	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	1	2	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Current	0.78	0.54	4.70	5.03
7 Days Ago	0.77	0.54	4.69	5.03
30 Days Ago	0.77	0.54	4.69	5.03
60 Days Ago	0.78	0.56	4.70	5.03
90 Days Ago	0.78	0.60	4.69	5.02

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Most Accurate Estimate	0.78	0.54	4.71	5.06
Zacks Consensus Estimate	0.78	0.54	4.70	5.03
Earnings ESP	-1.06%	0.00%	0.21%	0.60%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.95	1.47	0.49	0.68	NA
Estimate	1.94	1.49	0.48	0.69	NA
Difference	0.01	-0.02	0.01	-0.01	-0.00
Surprise	0.52%	-1.34%	2.08%	-1.45%	-0.05%

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NewJersey Resources Corporation (NJR)
(Real Time Quote from BATS)

$34.80 USD
-0.19 (-0.54%)
Updated May 29, 2020 02:47 PM ET

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Zacks Rank:
2-Buy

Style Scores:
B Value | D Growth | D Momentum | C VGM

Industry Rank:
Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

NewJersey Resources Corporation (NJR) Quote Overview » Estimates » NewJersey Resources Corporation (NJR) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	8/4/20	Earnings ESP	0.00%
Current Quarter	0.12	Current Year	2.10
EPS Last Quarter	1.12	Next Year	2.32
Last EPS Surprise	-21.68%	EPS (TTM)	1.65
ABR	2.75	P/E (F1)	16.66

Growth Estimates	NJR	IND	S&P
Current Qtr (06/2020)	160.00	17.86	-4.48
Next Qtr (09/2020)	58.62	-50.78	-50.17
Current Year (09/2020)	7.69	0.10	NA
Next Year (09/2021)	10.48	9.30	-4.94
Past 5 Years	2.30	2.30	NA
Next 5 Years	6.00	6.30	NA
PE	16.66	4.10	18.26
PEG Ratio	2.78	0.65	NA

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Premium Research for NJR

Zacks Rank	▲ Buy 2
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	B Value | D Growth | D Momentum | C VGM
Earnings ESP	0.00%
Research Report for NJR	Snapshot

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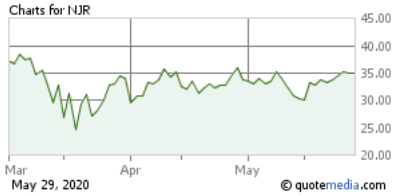

Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	460.00M	511.00M	2.23B	2.28B
# of Estimates	1	1	1	1
High Estimate	460.00M	511.00M	2.23B	2.28B
Low Estimate	460.00M	511.00M	2.23B	2.28B
Year ago Sales	434.94M	479.08M	2.59B	2.23B
Year over Year Growth Est.	5.76%	6.66%	-14.12%	2.52%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	0.12	0.46	2.10	2.32
# of Estimates	2	1	2	2
Most Recent Consensus	0.09	0.46	2.10	NA
High Estimate	0.14	0.46	2.10	2.40
Low Estimate	0.09	0.46	2.10	2.23
Year ago EPS	-0.20	0.29	1.95	2.10
Year over Year Growth Est.	160.00%	58.62%	7.69%	10.24%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	1	1	0
Up Last 60 Days	1	1	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Current	0.12	0.46	2.10	2.32
7 Days Ago	0.12	0.46	2.10	2.32
30 Days Ago	0.06	0.22	2.11	2.32
60 Days Ago	0.06	0.22	2.09	2.40
90 Days Ago	0.06	0.22	2.09	2.40

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Most Accurate Estimate	0.12	0.46	2.10	2.32
Zacks Consensus Estimate	0.12	0.46	2.10	2.32

Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.12	0.44	0.29	-0.20	NA
Estimate	1.43	0.79	0.31	0.13	NA
Difference	-0.31	-0.35	-0.02	-0.33	-0.25
Surprise	-21.68%	-44.30%	-6.45%	-253.85%	-81.57%

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Northwest Natural Gas Company (NWN)
(Real Time Quote from BATS)

$63.94 USD

-0.21 (-0.33%)

Updated May 29, 2020 02:47 PM ET

Add to port Trades from $1

Zacks Rank:

Style Scores:
NA Value | NA Growth | NA Momentum | NA VGM
Industry Rank:
Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

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Estimates

Next Report Date	8/4/20	Earnings ESP	NA
Current Quarter	NA	Current Year	NA
EPS Last Quarter	1.58	Next Year	NA
Last EPS Surprise	NA	EPS (TTM)	2.30
ABR	3.00	P/E (F1)	28.51

Growth Estimates	NWN	IND	S&P
Current Qtr (06/2020)	NA	17.86	-4.48
Next Qtr (09/2020)	NA	-50.78	-50.17
Current Year (12/2020)	2.70	0.10	NA
Next Year (12/2021)	NA	9.30	-4.90
Past 5 Years	-0.40	2.30	NA
Next 5 Years	NA	6.30	NA
PE	28.51	4.10	19.20
PEG Ratio	NA	0.65	NA

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Premium Research for NWN

Zacks Rank	NA
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	**NA Value | NA Growth | NA Momentum | NA VGM**
Earnings ESP	NA
Research Report for NWN	Snapshot

(= Change in last 30 days)

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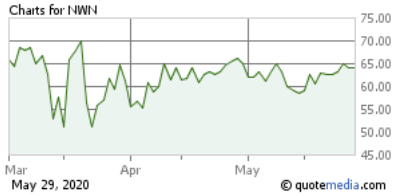
Chart for NWN



Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	0.00M	NA	NA	NA
# of Estimates	NA	NA	NA	NA
High Estimate	NA	NA	NA	NA
Low Estimate	NA	NA	NA	NA
Year ago Sales	123.00M	90.32M	745.93M	NA
Year over Year Growth Est.	NA	NA	NA	NA

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	NA	NA	2.25	NA
# of Estimates	0	0	1	0
Most Recent Consensus	NA	NA	NA	NA
High Estimate	NA	NA	2.25	NA
Low Estimate	NA	NA	2.25	NA
Year ago EPS	0.07	-0.61	2.19	2.25
Year over Year Growth Est.	NA	NA	2.74%	NA

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Up Last 7 Days	NA	NA	NA	NA
Up Last 30 Days	NA	NA	NA	NA
Up Last 60 Days	NA	NA	NA	NA
Down Last 7 Days	NA	NA	NA	NA
Down Last 30 Days	NA	NA	NA	NA
Down Last 60 Days	NA	NA	NA	NA

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Current	NA	NA	NA	NA
7 Days Ago	NA	NA	NA	NA
30 Days Ago	NA	NA	NA	NA
60 Days Ago	NA	NA	NA	NA
90 Days Ago	NA	NA	NA	NA

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Most Accurate Estimate	NA	NA	2.25	NA
Zacks Consensus Estimate	NA	NA	2.25	NA

Earnings ESP	NA	NA	0.00%	NA

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.58	1.26	-0.61	0.07	NA
Estimate	NA	NA	NA	-0.09	NA
Difference	NA	NA	NA	0.16	0.16
Surprise	NA	NA	NA	177.78%	177.78%

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ONE Gas, Inc. (OGS)
(Real Time Quote from BATS)

$83.71 USD
-0.53 (-0.63%)
Updated May 29, 2020 02:47 PM ET

Add to port Trades from $1

Zacks Rank:
3-Hold
Style Scores:
C Value | C Growth | B Momentum | C VGM
Industry Rank:
Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	8/3/20	Earnings ESP	0.00%
Current Quarter	0.46	Current Year	3.57
EPS Last Quarter	1.72	Next Year	3.83
Last EPS Surprise	-3.37%	EPS (TTM)	3.47
ABR	3.29	P/E (F1)	23.63

Growth Estimates	OGS	IND	S&P
Current Qtr (06/2020)	0.00	17.86	-4.48
Next Qtr (09/2020)	0.00	-50.78	-50.17
Current Year (12/2020)	1.71	0.10	NA
Next Year (12/2021)	7.28	9.30	-4.94
Past 5 Years	11.10	2.30	NA
Next 5 Years	5.50	6.30	NA
PE	23.63	4.10	18.26
PEG Ratio	4.30	0.65	NA

Learn More About Estimate Research
See Brokerage Recommendations
See Earnings Report Transcript

Premium Research for OGS

Zacks Rank	▼ Hold 3
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	C Value | C Growth | B Momentum | C VGM
Earnings ESP	0.00%
Research Reports for OGS	Analyst | Snapshot

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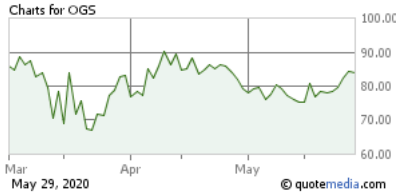
Research for OGS

Chart for OGS



Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	303.50M	265.80M	1.69B	1.76B
# of Estimates	1	1	2	2
High Estimate	303.50M	265.80M	1.69B	1.79B
Low Estimate	303.50M	265.80M	1.69B	1.73B
Year ago Sales	290.56M	248.56M	1.65B	1.69B
Year over Year Growth Est.	4.45%	6.94%	2.14%	4.34%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	0.46	0.33	3.57	3.83
# of Estimates	3	2	4	4
Most Recent Consensus	NA	0.32	3.50	3.78
High Estimate	0.47	0.33	3.62	3.87
Low Estimate	0.45	0.32	3.50	3.78
Year ago EPS	0.46	0.33	3.51	3.57
Year over Year Growth Est.	0.00%	0.00%	1.71%	7.35%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	1	0	0	2
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	2	4	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Current	0.46	0.33	3.57	3.83
7 Days Ago	0.46	0.33	3.57	3.83
30 Days Ago	0.46	0.33	3.57	3.83
60 Days Ago	0.46	0.38	3.62	3.82
90 Days Ago	0.46	0.38	3.61	3.81

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Most Accurate Estimate	0.46	0.33	3.58	3.87
Zacks Consensus Estimate	0.46	0.33	3.57	3.83

Earnings ESP	0.00%	0.00%	0.42%	1.11%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.72	0.96	0.33	0.46	NA
Estimate	1.78	0.95	0.34	0.41	NA
Difference	-0.06	0.01	-0.01	0.05	-0.00
Surprise	-3.37%	1.05%	-2.94%	12.20%	1.74%

Quarterly Estimates By Analyst

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South Jersey Industries, Inc. (SJI)

(Delayed Data from NYSE)

$28.14 USD

-0.51 (-1.78%)

Updated May 28, 2020 04:00 PM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

B Value | C Growth | D Momentum | B VGM

Industry Rank:

Top 13% (32 out of 248)
Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Estimates	
Next Report Date	8/5/20
Current Quarter	-0.03
EPS Last Quarter	1.15
Last EPS Surprise	2.68%
ABR	2.47
Earnings ESP	87.88%
Current Year	1.51
Next Year	1.70
EPS (TTM)	1.05
P/E (F1)	18.59

Growth Estimates	SJI	IND	S&P
Current Qtr (06/2020)	76.92	19.47	-14.33
Next Qtr (09/2020)	33.33	-49.98	-50.17
Current Year (12/2020)	34.82	0.10	NA
Next Year (12/2021)	12.58	9.30	-4.94
Past 5 Years	-5.80	2.30	NA
Next 5 Years	10.20	6.30	NA
PE	18.93	3.90	18.26
PEG Ratio	1.86	0.62	NA

Learn More About Estimate Research
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Premium Research for SJI

Zacks Rank	Hold 3
Zacks Industry Rank	Top 13% (32 out of 248)
Zacks Sector Rank	Top 19% (3 out of 16)
Style Scores	B Value | C Growth | D Momentum | B VGM
Earnings ESP	87.88%
Research Report for SJI	Snapshot

(▲ ▼ = Change in last 30 days)

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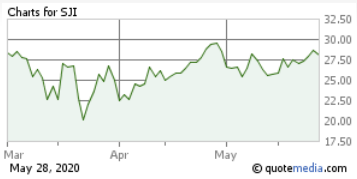
Research for SJI

Chart for SJI



Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	280.19M	283.14M	1.66B	1.71B
# of Estimates	2	2	2	2
High Estimate	282.38M	296.27M	1.75B	1.81B
Low Estimate	278.00M	270.00M	1.56B	1.62B
Year ago Sales	266.93M	261.20M	1.63B	1.66B
Year over Year Growth Est.	4.97%	8.40%	1.67%	3.48%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	-0.03	-0.20	1.51	1.70
# of Estimates	4	3	3	4
Most Recent Consensus	0.01	-0.14	1.53	NA

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
High Estimate	-0.06	-0.14	1.53	1.75
Low Estimate	-0.10	-0.30	1.49	1.66
Year ago EPS	-0.13	-0.30	1.12	1.51
Year over Year Growth Est.	76.92%	33.33%	34.82%	12.03%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	1	1
Up Last 60 Days	1	0	1	2
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	2	0	0
Down Last 60 Days	1	2	3	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Current	-0.03	-0.20	1.51	1.70
7 Days Ago	-0.03	-0.20	1.51	1.70
30 Days Ago	-0.01	-0.12	1.50	1.69
60 Days Ago	0.08	-0.08	1.54	1.65
90 Days Ago	0.12	-0.14	1.56	1.66

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Most Accurate Estimate	-0.00	-0.22	1.53	1.67
Zacks Consensus Estimate	-0.03	-0.20	1.51	1.70
Earnings ESP	87.88%	-8.20%	1.10%	-1.48%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.15	NA	-0.30	-0.13	NA
Estimate	1.12	NA	-0.27	-0.04	NA
Difference	0.03	NA	-0.03	-0.09	-0.03
Surprise	2.68%	NA	-11.11%	-225.00%	-77.81%

Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise

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Southwest Gas Corporation (SWX)
(Real Time Quote from BATS)

$75.96 USD
+0.28 (0.37%)
Updated May 29, 2020 02:47 PM ET

Add to port Trades from $1

Zacks Rank:
2-Buy
Style Scores:
B Value | C Growth | C Momentum | B VGM
Industry Rank:
Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	8/4/20	Earnings ESP	0.00%
Current Quarter	0.29	Current Year	3.74
EPS Last Quarter	1.59	Next Year	4.15
Last EPS Surprise	3.92%	EPS (TTM)	3.77
ABR	2.14	P/E (F1)	20.25

Growth Estimates	SWX	IND	S&P
Current Qtr (06/2020)	-29.27	17.86	-4.48
Next Qtr (09/2020)	160.00	-50.78	-50.17
Current Year (12/2020)	-5.08	0.10	NA
Next Year (12/2021)	10.96	9.30	-4.94
Past 5 Years	6.10	2.30	NA
Next 5 Years	6.00	6.30	NA
PE	20.25	4.10	18.26
PEG Ratio	3.38	0.65	NA

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Premium Research for SWX

Zacks Rank	▲ Buy 2
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	B Value | C Growth | C Momentum | B VGM
Earnings ESP	0.00%
Research Report for SWX	Snapshot

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Research for SWX

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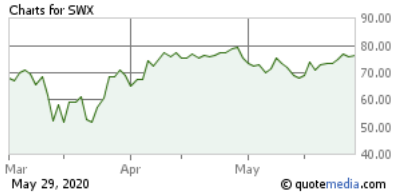

Interactive Chart | Fundamental Charts

Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	1.59	1.67	0.10	0.41	NA
Estimate	1.53	1.45	0.27	0.43	NA
Difference	0.06	0.22	-0.17	-0.02	0.02
Surprise	3.92%	15.17%	-62.96%	-4.65%	-12.13%

Quarterly Estimates By Analyst

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Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	753.98M	775.28M	3.28B	3.50B
# of Estimates	2	2	2	2
High Estimate	777.80M	791.60M	3.34B	3.67B
Low Estimate	730.15M	758.95M	3.22B	3.33B
Year ago Sales	713.01M	725.23M	3.12B	3.28B
Year over Year Growth Est.	5.75%	6.90%	5.09%	6.76%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Zacks Consensus Estimate	0.29	0.26	3.74	4.15
# of Estimates	2	2	3	3
Most Recent Consensus	NA	NA	3.68	4.13
High Estimate	0.29	0.30	3.80	4.22
Low Estimate	0.29	0.22	3.68	4.10
Year ago EPS	0.41	0.10	3.94	3.74
Year over Year Growth Est.	-29.27%	160.00%	-5.08%	11.05%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	1	3	2
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	1	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Current	0.29	0.26	3.74	4.15
7 Days Ago	0.29	0.26	3.74	4.15
30 Days Ago	0.29	0.26	3.74	4.15
60 Days Ago	0.35	0.16	3.71	4.04
90 Days Ago	0.31	0.22	3.84	4.21

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (12/2020)	Next Year (12/2021)
Most Accurate Estimate	0.29	0.26	3.74	4.15
Zacks Consensus Estimate	0.29	0.26	3.74	4.15

Zacks Research
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Cash flow Statements

Options

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Spire Inc. (SR)
(Real Time Quote from BATS)

$72.69 USD
+0.04 (0.06%)
Updated May 29, 2020 02:47 PM ET

Add to port Trades from $1

Zacks Rank:
3-Hold

Style Scores:
B Value | C Growth | B Momentum | B VGM

Industry Rank:
Top 16% (40 out of 254)
Industry: Utility - Gas Distribution

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	8/4/20	Earnings ESP	1.96%
Current Quarter	0.13	Current Year	3.73
EPS Last Quarter	2.75	Next Year	4.02
Last EPS Surprise	-6.78%	EPS (TTM)	3.61
ABR	2.91	P/E (F1)	19.46

Growth Estimates	SR	IND	S&P
Current Qtr (06/2020)	85.71	17.86	-4.48
Next Qtr (09/2020)	5.56	-50.78	-50.17
Current Year (09/2020)	0.00	0.10	NA
Next Year (09/2021)	7.77	9.30	-4.94
Past 5 Years	4.20	2.30	NA
Next 5 Years	4.70	6.30	NA
PE	19.46	4.10	18.26
PEG Ratio	4.11	0.65	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for SR

Zacks Rank	**Hold 3**
Zacks Industry Rank	Top 16% (40 out of 254)
Zacks Sector Rank	Top 13% (2 out of 16)
Style Scores	**B Value | C Growth | B Momentum | B VGM**
Earnings ESP	1.96%
Research Report for SR	Snapshot

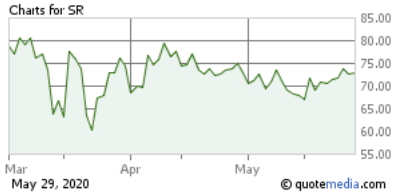
(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Research for SR

Chart for SR



Interactive Chart | Fundamental Charts

Sales Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	295.08M	231.99M	1.82B	1.80B
# of Estimates	2	2	3	3
High Estimate	298.28M	233.10M	1.86B	1.96B
Low Estimate	291.87M	230.87M	1.80B	1.69B
Year ago Sales	321.30M	225.60M	1.95B	1.82B
Year over Year Growth Est.	-8.16%	2.83%	-6.66%	-1.46%

Earnings Estimates

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Zacks Consensus Estimate	0.13	-0.51	3.73	4.02
# of Estimates	4	3	5	5
Most Recent Consensus	NA	NA	3.70	NA
High Estimate	0.17	-0.41	3.82	4.11
Low Estimate	0.08	-0.59	3.66	3.86
Year ago EPS	0.07	-0.54	3.73	3.73
Year over Year Growth Est.	85.71%	5.56%	0.00%	7.77%

Agreement - Estimate Revisions

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	1	0	1
Up Last 60 Days	0	1	0	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	4	2
Down Last 60 Days	2	1	4	2

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Current	0.13	-0.51	3.73	4.02
7 Days Ago	0.13	-0.51	3.73	4.02
30 Days Ago	0.14	-0.55	3.84	4.05
60 Days Ago	0.15	-0.55	3.83	4.03
90 Days Ago	0.17	-0.54	3.88	4.08

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2020)	Next Qtr (9/2020)	Current Year (9/2020)	Next Year (9/2021)
Most Accurate Estimate	0.13	-0.50	3.71	4.01
Zacks Consensus Estimate	0.13	-0.51	3.73	4.02

Earnings ESP	1.96%	1.96%	-0.58%	-0.43%

Surprise - Reported Earnings History

	Quarter Ending (3/2020)	Quarter Ending (12/2019)	Quarter Ending (9/2019)	Quarter Ending (6/2019)	Average Surprise
Reported	2.75	1.33	-0.54	0.07	NA
Estimate	2.95	1.26	-0.52	0.10	NA
Difference	-0.20	0.07	-0.02	-0.03	-0.05
Surprise	-6.78%	5.56%	-3.85%	-30.00%	-8.77%

Annual Estimates By Analyst

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S&P Futures 3,029.25 -8.75 (-0.29%)

Dow Futures 25,360.00 -97.00 (-0.38%)

Atmos Energy Corporation (ATO)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist 2W 10W 9M

Quote Lookup

101.68 +2.50 (+2.52%)

At close: 4:00PM EDT

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

Currency in USD

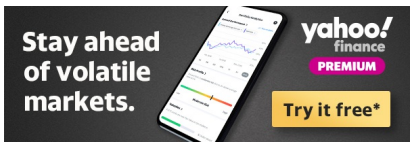
Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	9	9	10	11
Avg. Estimate	1.93	0.78	4.67	5.02
Low Estimate	1.72	0.7	4.6	4.94
High Estimate	2.15	0.89	4.72	5.13
Year Ago EPS	1.82	0.68	4.35	4.67

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	7	7
Avg. Estimate	1.18B	567.78M	3.22B	3.57B
Low Estimate	1.13B	529M	3.02B	3.21B
High Estimate	1.29B	640.69M	3.48B	3.97B
Year Ago Sales	N/A	N/A	2.9B	3.22B
Sales Growth (year/est)	N/A	N/A	11.00%	10.90%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.69	0.68	0.46	1.49
EPS Actual	1.82	0.68	0.49	1.47
Difference	0.13	0	0.03	-0.02
Surprise %	7.70%	0.00%	6.50%	-1.30%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.93	0.78	4.67	5.02
7 Days Ago	1.93	0.78	4.67	5.02
30 Days Ago	1.94	0.78	4.68	5.01
60 Days Ago	1.93	0.79	4.68	5.02
90 Days Ago	1.93	0.77	4.67	5.01

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	1
Up Last 30 Days	2	1	N/A	1



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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	1	N/A

Growth Estimates	ATO	Industry	Sector	S&P 500
Current Qtr.	6.00%	N/A	N/A	-0.34
Next Qtr.	14.70%	N/A	N/A	-0.12
Current Year	7.40%	N/A	N/A	-0.18
Next Year	7.50%	N/A	N/A	0.26
Next 5 Years (per annum)	7.50%	N/A	N/A	0.04
Past 5 Years (per annum)	8.41%	N/A	N/A	N/A

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Dow Futures 25,361.00 -96.00 (-0.38%)

New Jersey Resources Corporation (NJR)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist 2W 10W 9M

34.99 -0.25 (-0.71%)

At close: 4:00PM EDT

Quote Lookup

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

Currency in USD

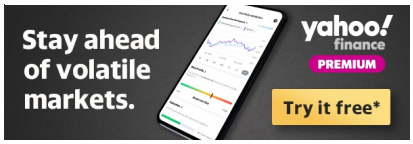
Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	6	6
Avg. Estimate	1.48	0.06	2.1	2.29
Low Estimate	1.37	-0.12	2.05	2.23
High Estimate	1.65	0.22	2.14	2.4
Year Ago EPS	1.27	-0.2	1.96	2.1

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	4	5
Avg. Estimate	872.39M	487.66M	2.7B	2.89B
Low Estimate	830.79M	469M	2.51B	2.76B
High Estimate	914M	506.32M	2.91B	3.02B
Year Ago Sales	N/A	N/A	2.59B	2.7B
Sales Growth (year/est)	N/A	N/A	4.20%	6.90%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.17	0.12	0.29	0.76
EPS Actual	1.27	-0.2	0.29	0.44
Difference	0.1	-0.32	0	-0.32
Surprise %	8.50%	-266.70%	0.00%	-42.10%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.48	0.06	2.1	2.29
7 Days Ago	1.48	0.06	2.1	2.29
30 Days Ago	1.48	0.05	2.09	2.31
60 Days Ago	1.48	0.05	2.1	2.37
90 Days Ago	1.33	0.04	2.12	2.38

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A



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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Up Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	NJR	Industry	Sector	S&P 500
Current Qtr.	16.50%	N/A	N/A	-0.34
Next Qtr.	130.00%	N/A	N/A	-0.12
Current Year	7.10%	N/A	N/A	-0.18
Next Year	9.00%	N/A	N/A	0.26
Next 5 Years (per annum)	6.00%	N/A	N/A	0.04
Past 5 Years (per annum)	50.73%	N/A	N/A	N/A

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S&P Futures 3,029.75 -8.25 (-0.27%)

Dow Futures 25,367.00 -90.00 (-0.35%)

Northwest Natural Holding Company (NWN)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist 2W 10W 9M

Quote Lookup

64.15 -0.84 (-1.29%)

At close: 4:00PM EDT

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	4	6	6
Avg. Estimate	1.57	0.02	2.36	2.55
Low Estimate	1.5	0	2.29	2.5
High Estimate	1.65	0.05	2.49	2.62
Year Ago EPS	1.72	0.04	2.29	2.36

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	3	3	5	5
Avg. Estimate	300.07M	128.02M	785.39M	823.96M
Low Estimate	288.2M	116M	754.6M	788.5M
High Estimate	310M	135.95M	835.53M	907.2M
Year Ago Sales	285.35M	123.44M	746.37M	785.39M
Sales Growth (year/est)	5.20%	3.70%	5.20%	4.90%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.39	-0.07	-0.53	1.22
EPS Actual	1.72	0.04	-0.63	1.2
Difference	0.33	0.11	-0.1	-0.02
Surprise %	23.70%	157.10%	-18.90%	-1.60%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.57	0.02	2.36	2.55
7 Days Ago	1.56	0.03	2.36	2.55
30 Days Ago	1.61	0.06	2.39	2.55
60 Days Ago	1.85	0.03	2.52	2.65
90 Days Ago	1.85	0.03	2.52	2.65

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	1	N/A	1	N/A
Up Last 30 Days	1	N/A	1	1

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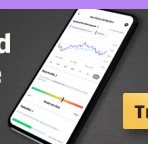

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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	2	1	1

Growth Estimates	NWN	Industry	Sector	S&P 500
Current Qtr.	-8.70%	N/A	N/A	-0.34
Next Qtr.	-50.00%	N/A	N/A	-0.12
Current Year	3.10%	N/A	N/A	-0.18
Next Year	8.10%	N/A	N/A	0.26
Next 5 Years (per annum)	3.75%	N/A	N/A	0.04
Past 5 Years (per annum)	-5.39%	N/A	N/A	N/A

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3,029.00
-9.00 (-0.30%)

Dow Futures
25,359.00
-98.00 (-0.38%)

ONE Gas, Inc. (OGS)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist | 2W 10W 9M

Quote Lookup

84.24 +1.98 (+2.41%)

At close: 4:00PM EDT

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials | Analysis | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Jun 2020)	Next Qtr. (Sep 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	8	8	8	8
Avg. Estimate	0.46	0.34	3.57	3.85
Low Estimate	0.41	0.32	3.52	3.78
High Estimate	0.48	0.37	3.62	3.93
Year Ago EPS	0.46	0.33	3.51	3.57

Revenue Estimate	Current Qtr. (Jun 2020)	Next Qtr. (Sep 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	6	7
Avg. Estimate	276.29M	241.92M	1.6B	1.7B
Low Estimate	239.81M	221.64M	1.4B	1.32B
High Estimate	303.5M	265.8M	1.69B	1.85B
Year Ago Sales	N/A	N/A	1.65B	1.6B
Sales Growth (year/est)	N/A	N/A	-3.00%	6.20%

Earnings History	6/29/2019	9/29/2019	12/30/2019	3/30/2020
EPS Est.	0.39	0.33	0.95	1.78
EPS Actual	0.46	0.33	0.96	1.72
Difference	0.07	0	0.01	-0.06
Surprise %	17.90%	0.00%	1.10%	-3.40%

EPS Trend	Current Qtr. (Jun 2020)	Next Qtr. (Sep 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.46	0.34	3.57	3.85
7 Days Ago	0.49	0.33	3.6	3.85
30 Days Ago	0.5	0.34	3.61	3.84
60 Days Ago	0.51	0.33	3.6	3.84
90 Days Ago	0.5	0.33	3.64	3.85

EPS Revisions	Current Qtr. (Jun 2020)	Next Qtr. (Sep 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	1	N/A	N/A	3
Up Last 30 Days	2	2	N/A	2

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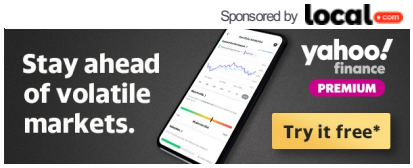

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EPS Revisions	Current Qtr. (Jun 2026)	Next Qtr. (Sep 2026)	Current Year (2026)	Next Year (2027)
Up Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	5	N/A	N/A	2

Growth Estimates	OGS	Industry	Sector	S&P 500
Current Qtr.	N/A	N/A	N/A	-0.34
Next Qtr.	3.00%	N/A	N/A	-0.12
Current Year	1.70%	N/A	N/A	-0.18
Next Year	7.80%	N/A	N/A	0.26
Next 5 Years (per annum)	5.00%	N/A	N/A	0.04
Past 5 Years (per annum)	15.32%	N/A	N/A	N/A

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3,028.50
-9.50 (-0.31%)

Dow Futures
25,353.00
-104.00 (-0.41%)

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South Jersey Industries, Inc. (SJI)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist 2W↓ 10W↑ 9M↑

Quote Lookup

28.14 -0.51 (-1.78%)

At close: 4:00PM EDT

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

Currency in USD

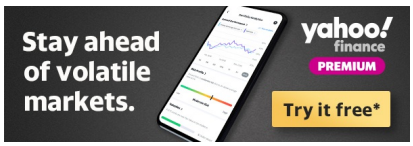
Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	8	8	8	8
Avg. Estimate	1.11	-0.03	1.49	1.68
Low Estimate	0.92	-0.25	1.25	1.62
High Estimate	1.25	0.24	1.59	1.75
Year Ago EPS	1.09	-0.13	1.12	1.49

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	6	6
Avg. Estimate	598.28M	267.06M	1.59B	1.66B
Low Estimate	468.4M	219.2M	1.28B	1.3B
High Estimate	666M	289.06M	1.88B	1.94B
Year Ago Sales	541.19M	254.12M	1.63B	1.59B
Sales Growth (year/est)	10.50%	5.10%	-2.10%	4.20%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.01	-0.04	-0.3	0.46
EPS Actual	1.09	-0.13	-0.3	0.47
Difference	0.08	-0.09	0	0.01
Surprise %	7.90%	-225.00%	0.00%	2.20%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.11	-0.03	1.49	1.68
7 Days Ago	1.08	-0.02	1.49	1.68
30 Days Ago	1.07	0.06	1.55	1.68
60 Days Ago	1.13	0.09	1.56	1.69
90 Days Ago	1.13	0.09	1.56	1.69

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	1	N/A	N/A	N/A
Up Last 30 Days	2	N/A	1	2



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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	N/A	N/A

Growth Estimates	SJI	Industry	Sector	S&P 500
Current Qtr.	1.80%	N/A	N/A	-0.34
Next Qtr.	76.90%	N/A	N/A	-0.12
Current Year	33.00%	N/A	N/A	-0.18
Next Year	12.80%	N/A	N/A	0.26
Next 5 Years (per annum)	10.20%	N/A	N/A	0.04
Past 5 Years (per annum)	13.27%	N/A	N/A	N/A

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Dow Futures 25,355.00 -102.00 (-0.40%)

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Southwest Gas Holdings, Inc. (SWX)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist 2W 10W 9M

Quote Lookup

75.68 -1.28 (-1.66%)

At close: 4:00PM EDT

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	7	7
Avg. Estimate	1.57	0.32	3.88	4.29
Low Estimate	1.5	0.12	3.68	4.13
High Estimate	1.64	0.56	4.3	4.64
Year Ago EPS	1.77	0.41	3.94	3.88

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	2	2
Avg. Estimate	538.75M	274.03M	1.46B	1.55B
Low Estimate	531.5M	266.1M	1.44B	1.55B
High Estimate	546M	281.96M	1.48B	1.56B
Year Ago Sales	520.68M	258.71M	1.37B	1.46B
Sales Growth (year/est)	3.50%	5.90%	6.60%	6.40%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.55	0.41	0.27	1.44
EPS Actual	1.77	0.41	0.1	1.67
Difference	0.22	0	-0.17	0.23
Surprise %	14.20%	0.00%	-63.00%	16.00%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.57	0.32	3.88	4.29
7 Days Ago	1.59	0.33	3.9	4.29
30 Days Ago	1.59	0.35	3.92	4.32
60 Days Ago	1.62	0.35	3.95	4.34
90 Days Ago	1.62	0.35	3.95	4.34

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	1	1
Up Last 30 Days	N/A	N/A	1	2

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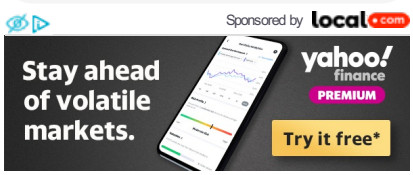

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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Up Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	2	2	1

Growth Estimates	SWX	Industry	Sector	S&P 500
Current Qtr.	-11.30%	N/A	N/A	-0.34
Next Qtr.	-22.00%	N/A	N/A	-0.12
Current Year	-1.50%	N/A	N/A	-0.18
Next Year	10.60%	N/A	N/A	0.26
Next 5 Years (per annum)	8.20%	N/A	N/A	0.04
Past 5 Years (per annum)	6.39%	N/A	N/A	N/A

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U.S. markets open in 2 hours 55 minutes

S&P Futures
3,028.75
-9.25 (-0.30%)

Dow Futures
25,354.00
-103.00 (-0.40%)

Spire Inc. (SR)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist | 2W↑ 10W↑ 9M↑

Quote Lookup

72.65 -1.09 (-1.48%)

At close: 4:00PM EDT

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials | Analysis | Options | Holders | Sustainability

Currency in USD

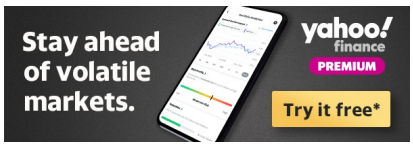
Earnings Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	9	8	9	8
Avg. Estimate	2.95	0.12	3.88	4.08
Low Estimate	2.89	0.07	3.82	3.97
High Estimate	3.03	0.17	3.95	4.2
Year Ago EPS	2.9	0.07	3.73	3.88

Revenue Estimate	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	7	7
Avg. Estimate	783.02M	327.75M	1.94B	2.02B
Low Estimate	706M	289M	1.69B	1.73B
High Estimate	814.63M	365.57M	2.04B	2.12B
Year Ago Sales	803.5M	N/A	1.95B	1.94B
Sales Growth (year/est)	-2.50%	N/A	-0.40%	3.80%

Earnings History	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	2.63	0.11	-0.52	1.31
EPS Actual	2.9	0.07	-0.54	1.33
Difference	0.27	-0.04	-0.02	0.02
Surprise %	10.30%	-36.40%	-3.80%	1.50%

EPS Trend	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	2.95	0.12	3.88	4.08
7 Days Ago	2.96	0.12	3.88	4.08
30 Days Ago	2.96	0.12	3.88	4.07
60 Days Ago	2.96	0.13	3.89	4.09
90 Days Ago	2.95	0.13	3.86	4.09

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	N/A	1	2



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EPS Revisions	Current Qtr. (Mar 2026)	Next Qtr. (Jun 2026)	Current Year (2026)	Next Year (2027)
Up Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	SR	Industry	Sector	S&P 500
Current Qtr.	1.70%	N/A	N/A	-0.34
Next Qtr.	71.40%	N/A	N/A	-0.12
Current Year	4.00%	N/A	N/A	-0.18
Next Year	5.20%	N/A	N/A	0.26
Next 5 Years (per annum)	4.65%	N/A	N/A	0.04
Past 5 Years (per annum)	-3.96%	N/A	N/A	N/A

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE **98.52** | P/E RATIO **21.4** (Trailing: 21.5 Median: 18.0) | RELATIVE P/E RATIO **1.18** | DIV'D YLD **2.5%** | **VALUE LINE**

TIMELINESS 3 Lowered 11/30/18
SAFETY 1 Raised 6/6/14
TECHNICAL 2 Lowered 5/29/20
BETA .80 (1.00 = Market)

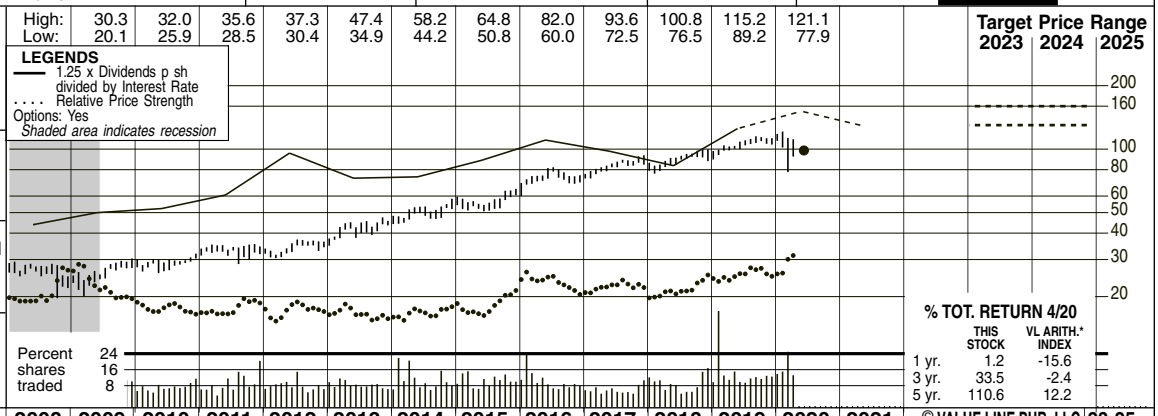
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$83-$183 $133 (35%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+60%)	*15%*
Low	130	(+30%)	*9%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	231	262	272
to Sell	206	193	215
Hld's(000)	99796	99815	102747



2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	*22.50*	*23.25*	Revenues per sh [A]	*37.95*
2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	*7.95*	*8.30*	"Cash Flow" per sh	*9.80*
1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	*4.60*	*4.85*	Earnings per sh [AB]	*6.00*
1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	*2.30*	*2.46*	Div'ds Decl'd per sh [C■]	*3.00*
3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	*15.20*	*15.40*	Cap'l Spending per sh	*15.50*
18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	*52.80*	*55.40*	Book Value per sh	*66.20*
62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	*125.00*	*130.00*	Common Shs Outst'g [D]	*145.00*
15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*24.0*
.84	.86	.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.27			Relative P/E Ratio	*1.35*
4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%			Avg Ann'l Div'd Yield	*2.1%*
4789.7	4347.6	3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	*2815*	*3020*	Revenues ($mill) [A]	*5500*
201.2	199.3	192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	*575*	*630*	Net Profit ($mill)	*870*
38.5%	36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	*22.0%*	*22.5%*	Income Tax Rate	*24.0%*
4.2%	4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	*20.4%*	*20.9%*	Net Profit Margin	*15.8%*
45.4%	49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
54.6%	50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
3987.9	4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	*11000*	*12000*	Total Capital ($mill)	*16000*
4793.1	5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	*13200*	*14400*	Net Plant ($mill)	*18000*
6.9%	6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	*8.5%*	*9.0%*	Return on Com Equity	*9.0%*
3.5%	3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
62%	62%	65%	56%	50%	51%	50%	50%	48%	48%	*50%*	*51%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $4529.0 mill. **Due in 5 Yrs** $465.0 mill.
LT Debt $4328.9 mill. **LT Interest** $255.0 mill.
(LT interest earned: 7.3x; total interest coverage: 7.3x)
Leases, Uncapitalized Annual rentals $21.0 mill.

Pfd Stock None

Pension Assets-9/19 $530.1 mill.
Oblig. $577.3 mill.
Common Stock 122,311,513 shs.
as of 5/1/20

MARKET CAP: $12.1 billion (Large Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	13.8	24.5	320.1
Other	465.1	433.5	509.5
Current Assets	478.9	458.0	829.6
Accts Payable	217.3	265.0	190.1
Debt Due	1150.8	464.9	200.1
Other	547.0	479.5	543.2
Current Liab.	1915.1	1209.4	933.4
Fix. Chg. Cov.	926%	990%	950%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-9.0%	-9.5%	*6.5%*
"Cash Flow"	5.5%	7.0%	*5.5%*
Earnings	7.5%	9.5%	*7.0%*
Dividends	4.0%	6.5%	*7.5%*
Book Value	6.5%	8.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	780.2	988.2	526.5	464.8	2759.7
2018	889.2	1219.4	562.2	444.7	3115.5
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	*501.8*	*460*	*2815*
2021	*900*	*1075*	*565*	*480*	*3020*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	1.08	1.52	.67	.34	3.60
2018	1.40	1.57	.64	.41	4.00
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	*.69*	*.49*	*4.60*
2021	*1.48*	*2.05*	*.76*	*.56*	*4.85*

Calendar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.42	.42	.42	.45	1.71
2017	.45	.45	.45	.485	1.84
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2019: 66%, residential; 27%, commercial; 5%, industrial; and 2% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.4% of common stock (12/19 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy posted a solid, 7% increase in share net through the first six months of fiscal 2020 (concludes September 30th), compared to the prior-year total. This was made possible partly by the natural gas distribution unit, which benefited from higher rates, mainly in the Mississippi, Mid-Tex, Louisiana, and West Texas divisions. Customer growth, largely in the Mid-Tex operation, also contributed. Meanwhile, the performance of the pipeline and storage division enjoyed an increase in revenue from a Gas Reliability Infrastructure Program filing approved in fiscal 2019. Lastly, the company's interest charges were lower.

But prospects for the remainder of the year are a bit unclear. The coronavirus is hampering the economy, evidenced by such factors as rising unemployment and disrupted supply chains. However, the severity of the pandemic cannot be determined at this juncture, since developments are constantly changing. Leadership contends that preventative measures have been taken, which include a greater emphasis on employees working remotely and adherence to social distancing and other government guidelines when working in the service territories. Still, erring on the side of caution, we currently expect full-year profits to be around $4.60 a share (around 6% growth), which is on the low side of the company's range of $4.58 to $4.73. Looking at fiscal 2021, a similar rate of increase, to $4.85 a share, seems plausible, assuming that the health crisis fades away.

Rate-filing efforts continue. During the first six months of fiscal 2020, Atmos was able to complete eight regulatory proceedings, resulting in a $59.2 million increase in annual operating income. What's more, some ratemaking initiatives were in progress at the time of this report, seeking $170 million of annual operating income. Of course, there are no guarantees that the company will get everything it wants.

Long-term total return potential is not outstanding, relative to other natural gas equities. In spite of the recent stock-price weakness (due to pandemic concerns), rebound potential over 2023-2025 remains unspectacular. The dividend yield is subpar, as well.

Frederick L. Harris, III *May 29, 2020*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. items: '10, 5¢; '11, (1¢); '18, $1.43. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Aug. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	100

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RECENT PRICE **33.33** | P/E RATIO **18.9** (Trailing: 20.2 Median: 17.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS 4 Lowered 4/3/20
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Raised 5/15/20
BETA .90 (1.00 = Market)

18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$25-$56 $41 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+35%)	*11%*
Low	35	(+5%)	*6%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	127	125	169
to Sell	102	102	99
Hld's(000)	60781	61471	67787

	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
High:	44.7	51.2	40.3	35.6	33.7	30.5	26.8	21.9	19.5	19.3	19.8	16.7	15.0					

LEGENDS
0.40 x Dividends p sh divided by Interest Rate
Relative Price Strength
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

Target Price Range 2023 2024 2025

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-30.4	-15.6
3 yr.	-9.1	-2.4
5 yr.	27.5	12.2

	2023-25	© VALUE LINE PUB. LLC	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
	30.05	Revenues per sh [A]	*28.35*	*23.70*	2.99	3.72	2.68	2.46	2.52	2.73	1.93	1.86	1.70	1.63	1.58	1.81	1.22	1.37	1.31	1.25
	3.55	"Cash Flow" per sh	*3.30*	*2.70*	1.96	2.72	1.73	1.61	1.78	2.08	1.37	1.36	1.29	1.23	1.20	1.35	.78	.93	.88	.85
	2.40	Earnings per sh [B]	*2.25*	*1.70*	1.19	1.11	1.04	.81	.93	.86	.81	.77	.72	.68	.62	.56	.51	.48	.45	.43
	1.57	Div'ds Decl'd per sh [C]■	*1.34*	*1.27*	1.19	1.11	1.04	.98	.93	.86	.81	.77	.72	.68	.62	.56	.51	.48	.45	.43
	4.00	Cap'l Spending per sh	*4.10*	*4.70*	5.83	4.39	3.80	4.15	3.76	1.52	1.33	1.26	1.13	1.05	.90	.86	.73	.64	.64	.72
	25.80	Book Value per sh [D]	*21.65*	*20.30*	17.37	16.18	14.33	13.58	12.99	11.48	10.65	9.80	9.36	8.81	8.29	8.64	7.75	7.50	5.30	5.62
	100.00	Common Shs Outst'g [E]	*97.00*	*96.00*	89.34	87.69	86.32	85.88	85.19	84.20	83.32	83.05	82.89	82.35	83.17	84.12	83.22	82.88	82.64	83.22
	17.0	Avg Ann'l P/E Ratio		*Bold figures are Value Line estimates*	24.3	15.6	22.4	21.3	16.6	11.7	16.0	16.8	16.8	15.0	14.9	12.3	21.6	16.1	16.8	15.3
	.95	Relative P/E Ratio			1.33	.84	1.13	1.12	.84	.62	.90	1.07	1.05	.95	.99	.74	1.15	.87	.89	.81
	3.7%	Avg Ann'l Div'd Yield			2.5%	2.6%	2.7%	2.9%	3.1%	3.5%	3.7%	3.4%	3.3%	3.7%	3.5%	3.3%	3.0%	3.2%	3.1%	3.3%
	3005	Revenues ($mill) [A]	*2750*	*2275*	2592.0	2915.1	2733.0	2879.2	2734.0	3738.1	3198.1	2248.9	3009.2	2639.3						
	240	Net Profit ($mill)	*220*	*165*	175.0	240.5	149.4	138.1	153.7	176.9	113.7	112.4	106.5	101.8						
	15.0%	Income Tax Rate	*15.0%*	*15.0%*	NMF	NMF	17.2%	15.5%	26.3%	30.2%	25.4%	7.1%	30.2%	41.4%						
	8.0%	Net Profit Margin	*7.2%*	*7.2%*	6.7%	8.2%	6.6%	7.3%	5.6%	4.7%	3.6%	5.0%	3.5%	3.9%						
	43.5%	Long-Term Debt Ratio	*44.5%*	*44.5%*	49.8%	45.4%	44.6%	47.7%	43.2%	38.2%	36.6%	39.2%	35.5%	37.2%						
	56.5%	Common Equity Ratio	*55.5%*	*55.5%*	50.2%	54.6%	55.4%	52.3%	56.8%	61.8%	63.4%	60.8%	64.5%	62.8%						
	4580	Total Capital ($mill)	*3800*	*3500*	3088.9	2599.6	2233.7	2230.1	1950.6	1564.4	1400.3	1339.0	1295.9	1154.4						
	4115	Net Plant ($mill)	*3875*	*3800*	3041.2	2651.0	2609.7	2407.7	2128.3	1884.1	1643.1	1484.9	1295.9	1135.7						
	6.0%	Return on Total Cap'l	*6.5%*	*5.5%*	6.4%	10.1%	7.7%	6.9%	8.6%	12.1%	9.0%	9.2%	9.7%	9.7%						
	9.5%	Return on Shr. Equity	*10.5%*	*8.5%*	11.3%	16.9%	12.1%	11.8%	13.9%	18.3%	12.8%	13.8%	13.7%	14.0%						
	9.5%	Return on Com Equity	*10.5%*	*8.5%*	11.3%	16.9%	12.1%	11.8%	13.9%	18.3%	12.8%	13.8%	13.7%	14.0%						
	3.0%	Retained to Com Eq	*4.5%*	*2.0%*	4.6%	10.2%	5.0%	4.8%	7.0%	11.0%	5.2%	6.2%	6.2%	6.7%						
	65%	All Div'ds to Net Prof	*59%*	*74%*	59%	40%	59%	60%	50%	40%	59%	55%	55%	52%						

CAPITAL STRUCTURE as of 3/31/20
Total Debt $2065.3 mill. **Due in 5 Yrs** $420.5 mill.
LT Debt $1576.7 mill. **LT Interest** $47.1 mill.
Incl. $38.6 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/19 $372.6 mill.
Oblig. $620.5 mill.
Pfd Stock None

Common Stock 95,752,020 shs.
as of 5/6/20
MARKET CAP: $3.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	1.5	2.7	25.9
Other	768.6	508.9	475.0
Current Assets	770.1	511.6	500.9
Accts Payable	373.5	295.9	250.5
Debt Due	275.5	46.9	488.6
Other	101.9	103.6	85.2
Current Liab.	750.9	446.4	824.3
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.5%	-4.0%	*.5%*
"Cash Flow"	7.5%	7.5%	*2.0%*
Earnings	7.0%	6.0%	*2.0%*
Dividends	7.0%	6.5%	*6.0%*
Book Value	7.0%	8.5%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	541.1	733.5	457.5	536.5	2268.6
2018	705.3	1019.0	543.4	647.3	2915.1
2019	811.8	866.3	434.9	479.1	2592.0
2020	615.0	639.6	*485*	*535.4*	*2275*
2021	*665*	*965*	*535*	*585*	*2750*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	.47	1.21	.20	d.14	1.73
2018	1.53	1.61	d.09	d.33	2.72
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	*d.14*	*.28*	*1.70*
2021	*.50*	*1.50*	*d.10*	*.35*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.24	.24	.24	.255	.98
2017	.255	.255	.255	.273	1.04
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 547,600 cust. at 9/30/19. Fiscal 2019 volume: 232 bill. cu. ft. (17% interruptible, 17% res., 9% commercial & elec. utility, 40% capacity release programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2019 dep. rate: 2.6%. Has 1,108 empls. Off./dir. own 1.3% of common; BlackRock, 13.9%; Vanguard, 10.4% (12/19 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

Since our February review, shares of New Jersey Resources have staged a hefty correction. Indeed, over that time frame, the equity's price has fallen more than 20%. This likely reflects the challenging operating environment caused by the coronavirus pandemic; the sharp rise in unemployment; and the fact that many utility providers have assured customers that there will not be an interruption in service despite some customers not being able to pay bills due to economic hardship. **Meanwhile, the retail and wholesale energy services provider posted lower-than-expected March-quarter financial results.** In fact, the top line fell 26.2%, to $639.6 million, as NJR's nonutility and utility volumes declined 39.4% and 1.4%, to $342.4 million and $297.2 million, respectively. On the profitability front, total expenses receded by 600 basis points when viewed as a percentage of sales. After accounting for the dilutive effects of a nearly 6.7-million-share increase in common stock outstanding, the fiscal second-quarter share net registered an 11.8% downturn, to $1.12. This was markedly below our call for earnings of $1.45.

Consequently, we have reduced our outlook for this fiscal year (ends September 30th). New Jersey Resources appears poised to log a revenue shortfall of approximately 12%, to $2.275 billion, due largely to volatility in commodity prices and a significant drop in the market rate for fossil fuels. These record low prices are greatly weighing on the nonutility operations. What's more, the recent issuance of stock may help to shore up NJR's cash position, but it is diluting share net. Therefore, we have sliced $0.35 from our 2020 bottom-line estimate, to $1.70 a share. This figure would represent a more-than-13% drop in earnings.

The balance sheet is in good shape. Cash reserves have swelled nearly tenfold, due to stock offerings, to $25.9 billion. Meanwhile, the long-term debt load has remained stable, but management has secured a $425 million short-term revolver, which should help it to weather the current economic downturn.

At the recent quotation, these untimely shares appear richly valued.

Bryan J. Fong *May 29, 2020*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. sales and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early Aug.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2019: $496.6 million, $5.56/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	70
Earnings Predictability	45

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N.W. NATURAL NYSE-NWN

RECENT PRICE 62.54 | P/E RATIO 25.5 (Trailing: 27.2 Median: 23.0) | RELATIVE P/E RATIO 1.41 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 5/22/20
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Raised 4/3/20
BETA .80 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$47-$104 $76 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+35%)	10%
Low	70	(+10%)	6%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	124	107	120
to Sell	70	90	95
Hld's(000)	21542	21608	23102

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	46.5	50.9	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3						
Low:	37.7	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	50.5						

Target Price Range 2023 2024 2025

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.6	-15.6
3 yr.	18.4	-2.4
5 yr.	62.0	12.2

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25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	*24.50*	*25.75*	Revenues per sh	*29.40*
3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	*4.90*	*5.30*	"Cash Flow" per sh	*6.45*
1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	*2.45*	*2.70*	Earnings per sh A	*3.50*
1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	*1.91*	*1.92*	Div'ds Decl'd per sh B■	*1.97*
5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	*7.80*	*6.15*	Cap'l Spending per sh	*6.25*
20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	*29.65*	*31.80*	Book Value per sh D	*29.85*
27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	*31.00*	*31.00*	Common Shs Outst'g C	*32.00*
16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*22.0*
.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.68			Relative P/E Ratio	*1.20*
4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%			Avg Ann'l Div'd Yield	*2.9%*
812.1	848.8	730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	*760*	*820*	Revenues ($mill)	*940*
72.7	63.9	59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	*75.0*	*85.0*	Net Profit ($mill)	*95.0*
40.5%	40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
8.9%	7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	*10.0%*	*10.5%*	Net Profit Margin	*11.9%*
46.1%	47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	*47.5%*	*47.0%*	Long-Term Debt Ratio	*47.5%*
53.9%	52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	*52.5%*	*53.0%*	Common Equity Ratio	*52.5%*
1284.8	1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	*1755*	*1850*	Total Capital ($mill)	*1825*
1854.2	1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	*2535*	*2640*	Net Plant ($mill)	*3065*
7.0%	6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*7.5%*
10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	*8.5%*	*8.5%*	Return on Shr. Equity	*11.5%*
10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	*8.5%*	*8.5%*	Return on Com Equity	*11.5%*
4.0%	2.4%	1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	*2.0%*	*2.5%*	Retained to Com Eq	*5.0%*
61%	73%	80%	81%	85%	92%	87%	NMF	76%	82%	*78%*	*71%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $1504.0 mill. **Due in 5 Yrs** $910.0 mill.
LT Debt $954.0 mill. **LT Interest** $40.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/19 $313.1 mill.
Oblig. $515.7 mill.

Pfd Stock None

Common Stock 30,528,958 shares
as of 4/28/20

MARKET CAP $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	12.6	9.6	471.1
Other	283.3	284.1	249.2
Current Assets	295.9	293.7	720.3
Accts Payable	115.9	113.4	23.9
Debt Due	247.6	224.2	550.0
Other	145.6	144.6	225.0
Current Liab.	509.1	482.2	798.9
Fix. Chg. Cov.	357%	336%	336%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-4.0%	-2.0%	*2.5%*
"Cash Flow"	-3.0%	-5.5%	*9.0%*
Earnings	-11.0%	-17.0%	*26.5%*
Dividends	2.0%	.5%	*.5%*
Book Value	1.5%	-.5%	*2.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	297.3	136.3	88.2	240.4	762.2
2018	264.7	124.6	91.2	226.7	706.1
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	*125*	*100*	*249.8*	*760*
2021	*305*	*145*	*110*	*260*	*820*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.40	.10	d.30	d3.14	d1.94
2018	1.46	d.01	d.39	1.27	2.33
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	*.02*	*d.40*	*1.25*	*2.45*
2021	*1.60*	*.10*	*d.35*	*1.35*	*2.70*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.4675	.4675	.4675	.470	1.87
2017	.470	.470	.470	.4725	1.88
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1000 communities, 750,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 15.5% of shares; Off./Dir. own less than 1% (4/20 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holding recorded improved first-quarter results. Revenues came in about even with the prior-year period, as reduced prices for natural gas offset a greater number of customers, primarily driven by additional demand from the Mist storage facility. Meantime, the Oregon coverage area added 12,400 new customers over the past 12 months, boosting that total 1.6%. However, the weather was warmer in Oregon, partially offsetting some of the positives there. Maintenance expense was about flat year over year, and the company benefited from reduced pension expense in the quarter, but a slightly higher share count hampered share-net expansion. Overall, these factors allowed earnings to rise to $1.58 per share during the period. Northwest is in decent shape, as operations will likely not be affected all that much by the coronavirus, given its focus on residential customers. Overall, we estimate that profits should rise to $2.45 per share this year.

The company further extended the date of its Gil Ranch storage facility sale to June 26th. Management had been looking to divest its stake in the business, and though it has been postponed the sale once before. Northwest has been working to improve its asset mix, and we think this will be completed in the second quarter and will result in a one-time gain.

The company is on track for better performance in the years ahead. Operations will probably benefit from higher revenues, as Northwest recently purchased a water utility in Texas, which further expands operations in that industry. Too, the company has filed for $71.4 million in rate hikes in Oregon, which should help the top line if approved. Overall, we think profits will increase to $2.70 per share in 2021, and $3.50 per share by the 2023-2025 period.

Shares of Northwest Natural Holding are neutrally ranked for Timeliness. The shares have fallen over the past three months, though appreciation potential is lower than average. The dividend yield is now above average and is well covered by earnings. Too, Northwest holds our Highest (1) rank for Safety. All told, this stock is a decent choice for income-seeking accounts.

John E. Seibert III *May 29, 2020*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2019: $343.2 million, $11.26/share.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	5

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 80.66 | P/E RATIO 23.4 (Trailing: 23.2 Median: NMF) | RELATIVE P/E RATIO 1.29 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 2/28/20
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 5/8/20
BETA .80 (1.00 = Market)

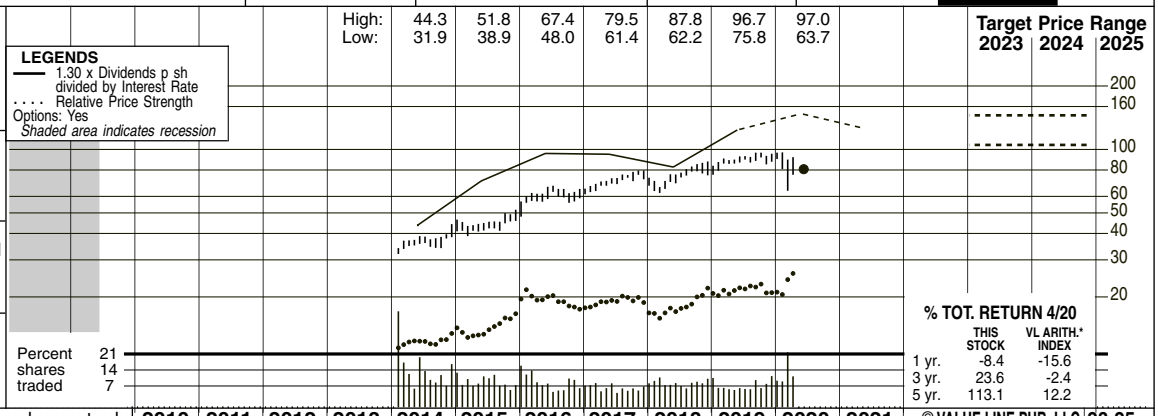
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$64-$137 $101 (25%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+80%)	*18%*
Low	105	(+30%)	*9%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	135	133	153
to Sell	145	132	132
Hld's(000)	40275	40475	41714



The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 3/31/20
Total Debt $1760.9 mill. **Due in 5 Yrs** $1030.0 mill.
LT Debt $1286.2 mill. **LT Interest** $75.0 mill.
(LT interest earned: 4.7x; total interest coverage: 4.7x)
Leases, Uncapitalized Annual rentals $7.6 mill.
Pfd Stock None
Pension Assets-12/19 $908.0 mill.
Oblig. $1001.4 mill.
Common Stock 52,865,557 shs.
as of 4/20/20
MARKET CAP: $4.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	21.3	17.9	11.1
Other	522.0	488.3	396.6
Current Assets	543.3	506.2	407.7
Accts Payable	174.5	120.5	82.1
Debt Due	299.5	516.5	474.7
Other	224.9	235.7	219.4
Current Liab.	698.9	872.7	776.2
Fix. Chg. Cov.	677%	567%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	- -	-2.5%	*4.5%*
"Cash Flow"	- -	7.0%	*6.5%*
Earnings	- -	9.5%	*6.5%*
Dividends	- -	17.0%	*7.5%*
Book Value	- -	2.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	550.4	279.7	247.1	462.4	1539.6
2018	638.5	292.5	238.3	464.4	1633.7
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	*285*	*245*	*456.8*	*1515*
2021	*580*	*315*	*260*	*465*	*1620*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.34	.39	.36	.93	3.02
2018	1.72	.39	.31	.83	3.25
2019	1.76	.46	.33	.96	3.51
2020	1.72	*.46*	*.32*	*.95*	*3.45*
2021	*1.80*	*.50*	*.36*	*.99*	*3.65*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.35	.35	.35	.35	1.40
2017	.42	.42	.42	.42	1.68
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54			

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
	--	--	--	--	34.92	29.62	27.30	29.43	31.08	31.32	*28.60*	*30.30*	Revenues per sh	*40.00*
	--	--	--	--	4.52	4.82	5.43	5.96	6.32	6.96	*7.15*	*7.55*	"Cash Flow" per sh	*9.30*
	--	--	--	--	2.07	2.24	2.65	3.02	3.25	3.51	*3.45*	*3.65*	Earnings per sh A	*4.75*
	--	--	--	--	.84	1.20	1.40	1.68	1.84	2.00	*2.16*	*2.32*	Div'ds Decl'd per sh B■	*2.80*
	--	--	--	--	5.70	5.63	5.91	6.81	7.50	7.91	*8.50*	*8.70*	Cap'l Spending per sh	*9.35*
	--	--	--	--	34.45	35.24	36.12	37.47	38.86	40.35	*42.10*	*43.85*	Book Value per sh	*49.60*
	--	--	--	--	52.08	52.26	52.28	52.31	52.57	52.77	*53.00*	*53.50*	Common Shs Outst'g C	*55.00*
	--	--	--	--	17.8	19.8	22.7	23.5	23.1	25.3	*Bold figures are*		Avg Ann'l P/E Ratio	*26.5*
	--	--	--	--	.94	1.00	1.19	1.18	1.25	1.37	*Value Line*		Relative P/E Ratio	*1.45*
	--	--	--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	*estimates*		Avg Ann'l Div'd Yield	*2.2%*
	--	--	--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	*1515*	*1620*	Revenues ($mill)	*2200*
	--	--	--	--	109.8	119.0	140.1	159.9	172.2	186.7	*185*	*195*	Net Profit ($mill)	*260*
	--	--	--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	*19.0%*	*19.5%*	Income Tax Rate	*22.0%*
	--	--	--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	*12.2%*	*12.0%*	Net Profit Margin	*11.8%*
	--	--	--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	*38.0%*	*38.0%*	Long-Term Debt Ratio	*38.0%*
	--	--	--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	*62.0%*	*62.0%*	Common Equity Ratio	*62.0%*
	--	--	--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	*3600*	*3785*	Total Capital ($mill)	*4400*
	--	--	--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	*4800*	*5030*	Net Plant ($mill)	*5750*
	--	--	--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*4.0%*
	--	--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.5%*
	--	--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	*8.5%*	*8.5%*	Return on Com Equity	*9.5%*
	--	--	--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
	--	--	--	--	40%	53%	52%	55%	56%	56%	*62%*	*64%*	All Div'ds to Net Prof	*59%*

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 174 Bcf of natural gas supply in 2019, compared to 180 Bcf in 2018. Total volumes delivered by customer (fiscal 2019): transportation, 56.6%; residential, 32.5%; commercial & industrial, 10.3%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 12.1% of common stock; The Vanguard Group, 10.1%; T. Rowe Price Associates, 7.0%; officers and directors, 1.9% (4/20 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. got off to an uninspiring start in 2020. Indeed, first-quarter share net of $1.72 was 2.3% below last year's $1.76 tally. This was attributable, to some extent, to lower gas sales, net of weather normalization, mainly in Kansas and Oklahoma because of warmer temperatures. Also, there was a drop in transportation volumes in Kansas plus a higher effective income tax rate.

The path might be a bit rough over the course of this year. The coronavirus is now having a larger, unfavorable effect on results. But the company argues that the impact will be partially offset by regulatory actions allowing it to use an accounting mechanism to accumulate and defer certain incremental costs incurred (including bad-debt expenses) and lost revenues in connection with the pandemic. What's more, management implemented a comprehensive set of procedures to protect the safety of employees and customers. Still, right now, it appears that full-year profits will decrease about 2%, to $3.45 a share, versus the 2019 total of $3.51. Turning to 2021, though, we expect share net to rebound nearly 6%, to $3.65, if, of course, the health crisis diminishes in intensity.

Finances are healthy. When the first quarter ended, cash and equivalents stood at around $11 million, and cash flows were decent (although they may slow some in the months ahead). Too, long-term debt resided at a reasonable 37% of total capital, and short-term commitments did not appear to be a major problem. Furthermore, there was $474.7 million available (out of $700 million) under a commercial paper program. ONE Gas also holds a $700 million revolving credit facility expiring October 2024, and in April, it entered into a 364-day, $250 million revolving credit agreement. All things considered, the company ought to continue to satisfy its various obligations, such as working capital and dividend payments.

The stock offers decent long-term total return potential for a natural gas utility. The dividend should remain on a steady, upward trajectory. Moreover, the recent price drop (given pandemic concerns), has increased 3- to 5-year recovery possibilities.

Frederick L. Harris, III *May 29, 2020*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS for 2018 don't add up due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

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SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **27.74** | P/E RATIO **17.9** (Trailing: 24.8 Median: 19.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **4.4%** | **VALUE LINE**

TIMELINESS 3 Lowered 7/20/18
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Raised 4/24/20
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$21-$52 $37 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+60%)	*16%*
Low	35	(+25%)	*10%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	111	101	124
to Sell	99	100	95
Hld's(000)	77450	77210	79196

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	20.4	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4						
Low:	16.0	18.6	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	19.6						

Target Price Range 2023 2024 2025

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.5	-15.6
3 yr.	-15.1	-2.4
5 yr.	30.3	12.2

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	*16.65*	*17.55*	Revenues per sh	*21.55*
	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	*2.70*	*3.00*	"Cash Flow" per sh	*3.95*
	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	*1.55*	*1.75*	Earnings per sh [A]	*2.50*
	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	*1.20*	*1.25*	Div'ds Decl'd per sh [B] ■	*1.40*
	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	*6.30*	*6.70*	Cap'l Spending per sh	*7.85*
	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	*16.85*	*17.80*	Book Value per sh [C]	*20.60*
	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	*95.00*	*97.00*	Common Shs Outst'g [D]	*102.00*
	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.53			Relative P/E Ratio	*.90*
	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%			Avg Ann'l Div'd Yield	*3.5%*
							925.1	828.6	706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	*1580*	*1700*	Revenues ($mill)	*2200*
							81.0	87.0	93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	*145*	*170*	Net Profit ($mill)	*255*
							15.2%	22.4%	10.8%	--	--	5.9%	42.0%	--	42.0%	22.0%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							8.8%	10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	*9.2%*	*10.0%*	Net Profit Margin	*11.6%*
							37.4%	40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	*58.0%*	*57.5%*	Long-Term Debt Ratio	*56.5%*
							62.6%	59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	*42.0%*	*42.5%*	Common Equity Ratio	*43.5%*
							910.1	1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	*3800*	*4075*	Total Capital ($mill)	*4850*
							1193.3	1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	*4500*	*4850*	Net Plant ($mill)	*6000*
							9.5%	8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.5%*
							14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	*9.0%*	*10.0%*	Return on Shr. Equity	*12.0%*
							14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	*9.0%*	*10.0%*	Return on Com Equity	*12.0%*
							7.1%	6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	*2.0%*	*3.0%*	Retained to Com Eq	*5.5%*
							50%	52%	55%	59%	61%	71%	80%	89%	82%	104%	*79%*	*71%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $3234.8 mill. **Due in 5 Yrs** $1045 mill.
LT Debt $2067.1 mill. **LT Interest** $80.0 mill.

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/19 $312.5 mill.
Oblig. $439.4 mill.

Pfd Stock None

Common Stock 92,462,219 shs.
as of 5/1/20

MARKET CAP: $2.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	30.0	6.4	10.3
Other	633.2	646.1	452.0
Current Assets	663.2	652.5	462.3
Accts Payable	410.5	232.2	187.6
Debt Due	1004.4	1316.6	1167.7
Other	165.9	183.1	210.4
Current Liab.	1580.8	1731.9	1565.7
Fix. Chg. Cov.	112%	176%	196%

ANNUAL RATES (of change (per sh))	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	--	6.0%	*3.5%*
"Cash Flow"	5.0%	3.5%	*6.0%*
Earnings	1.5%	-2.5%	*12.5%*
Dividends	8.0%	6.0%	*3.5%*
Book Value	6.5%	6.0%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	425.8	244.4	227.1	345.8	1243.1
2018	521.9	227.3	302.5	589.6	1641.3
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	*270*	*275*	*500.9*	*1580*
2021	*580*	*290*	*295*	*535*	*1700*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.72	.06	d.05	.50	1.23
2018	1.19	.07	d.27	.39	1.38
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	*.05*	*d.15*	*.50*	*1.55*
2021	*1.20*	*.10*	*d.10*	*.55*	*1.75*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	--	.264	.264	.536	1.06
2017	--	.273	.273	.553	1.10
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295			

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '19: residential, 47%; commercial, 23%; cogen. and electric gen., 12%; industrial, 18%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. operations include South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,100 employees. Off./dir. own less than 1% of common; BlackRock, 15.5%; The Vanguard Group, 11.4% (3/20 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have rebounded in price lately, following a selloff earlier in the year resulting from the spread of the coronavirus. The company posted mixed results for the March quarter. The top line declined roughly 16% year to year. But cost of sales fell significantly, and operating expenses remained in check. All told, earnings per share of $1.15 compared favorably with the prior-year tally of $1.09.

Considerable economic weakness ought to impact the top line this year. We have lowered our revenue estimate for full-year 2020, to $1.58 billion. Operations and delivery of natural gas to customers have not been materially affected by the coronavirus pandemic, though some incremental costs have been incurred for emergency response, and construction activity has ceased in response to government directives. Overall, we anticipate that expenses will remain subdued in the coming quarters, and that earnings per share of $1.55 for the full year will be a marked improvement from the 2019 level.

We expect a top-line rebound in 2021, and further share-net improvement. Healthy growth ought to continue thereafter. This should be driven by the company's utility operations and regulatory initiatives. These businesses will likely continue to benefit from growth in the customer base. Infrastructure investments to modernize its system should allow South Jersey to meet increasing demand for natural gas in its service territories. Infrastructure replacement programs allow this business to earn an authorized return on approved investments. We expect a measure of improvement from the company's nonutility operations, as well.

This stock is ranked to track the broader market averages for the coming six to 12 months. Aggressive accounts seeking wide capital gains potential should look elsewhere. But conservative investors looking for exposure to the utilities sector may want to take a closer look. South Jersey Industries earns good marks for Safety and Price Stability. Volatility is subdued, as well. All told, the shares offer decent total return potential, on a risk-adjusted basis. This is helped by a generous dividend yield.

Michael Napoli, CFA *May 29, 2020*

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	20
Earnings Predictability	60

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(A) Based on economic egs. from 2007. GAAP EPS: '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84. Excl. nonrecur. gain (loss): '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28). Next egs. rpt. due early August. **(B)** Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. **(C)** Incl. reg. assets. In 2019: $665.9 mill., $7.21 per shr. **(D)** In mill., adj. for split.

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 74.10 | P/E RATIO 21.8 (Trailing: 21.2 Median: 18.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Raised 3/20/20
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 5/22/20
BETA .90 (1.00 = Market)

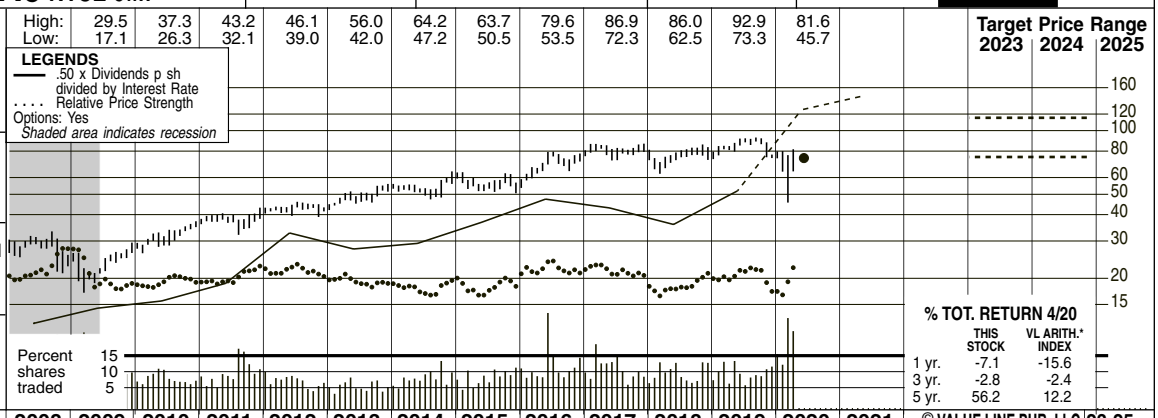
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$69-$109 $89 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+55%)	*14%*
Low	75	(Nil)	*4%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	126	153	155
to Sell	141	122	136
Hld's(000)	45661	45864	47563



2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	***56.60***	***59.00***	Revenues per sh	*65.40*
5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	***9.30***	***10.00***	"Cash Flow" per sh	*13.25*
1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	***3.40***	***4.00***	Earnings per sh [A]	*6.00*
.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	***2.26***	***2.35***	Div'ds Decl'd per sh [B■†]	*2.65*
8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	***15.45***	***17.80***	Cap'l Spending per sh	*21.55*
19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	***48.25***	***50.85***	Book Value per sh	*60.00*
36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	***57.00***	***59.00***	Common Shs Outst'g [C]	*65.00*
14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.76	1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.15			Relative P/E Ratio	*.90*
3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%			Avg Ann'l Div'd Yield	*2.8%*
1830.4	1887.2	1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	***3225***	***3480***	Revenues ($mill)	*4250*
103.9	112.3	133.3	145.3	141.1	138.3	152.0	173.8	182.3	213.9	***190***	***230***	Net Profit ($mill)	*380*
34.7%	36.2%	36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	***21.0%***	***21.0%***	Income Tax Rate	*21.0%*
5.7%	6.0%	6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	***5.9%***	***6.6%***	Net Profit Margin	*8.9%*
49.1%	43.2%	49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	***47.5%***	***47.0%***	Long-Term Debt Ratio	*44.5%*
50.9%	56.8%	50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	***52.5%***	***53.0%***	Common Equity Ratio	*55.5%*
2291.7	2155.9	2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	***5250***	***5650***	Total Capital ($mill)	*7000*
3072.4	3218.9	3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	***6000***	***6400***	Net Plant ($mill)	*7600*
6.1%	6.4%	6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	***4.5%***	***5.0%***	Return on Total Cap'l	*6.5%*
8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	***7.0%***	***7.5%***	Return on Shr. Equity	*9.5%*
8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	***7.0%***	***7.5%***	Return on Com Equity	*9.5%*
5.1%	5.3%	6.1%	6.1%	5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	***2.0%***	***3.0%***	Retained to Com Eq	*5.5%*
43%	43%	40%	41%	47%	54%	55%	53%	55%	54%	***68%***	***60%***	All Div'ds to Net Prof	*45%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $2636.7 mill. **Due in 5 Yrs** $898.8 mill.
LT Debt $2310.1 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 3.3x) (47% of Cap'l)
Leases, Uncapitalized Annual rentals $13.0 mill.
Pension Assets-12/19 $1027.8 mill.
Oblig. $1405.7 mill.

Pfd Stock None

Common Stock 55,129,976 shs.
as of 4/30/20

MARKET CAP: $4.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	85.4	49.5	61.0
Other	754.4	810.4	611.9
Current Assets	839.8	859.9	672.9
Accts Payable	249.0	238.9	182.2
Debt Due	185.1	374.5	326.6
Other	504.5	466.5	471.0
Current Liab.	938.6	1079.9	979.8
Fix. Chg. Cov.	370%	340%	341%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.5%	5.0%	*3.0%*
"Cash Flow"	4.0%	1.5%	*7.0%*
Earnings	8.0%	4.5%	*8.0%*
Dividends	8.5%	9.5%	*4.0%*
Book Value	6.0%	6.5%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	654.7	560.5	593.2	740.4	2548.8
2018	754.3	670.9	668.1	786.7	2880.0
2019	833.6	713.0	725.2	848.1	3119.9
2020	836.3	***760***	***760***	***868.7***	***3225***
2021	***890***	***825***	***825***	***940***	***3480***

Calendar	EARNINGS PER SHARE [A D] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.45	.37	.21	1.58	3.62
2018	1.63	.44	.25	1.36	3.68
2019	1.77	.41	.10	1.67	3.94
2020	1.31	***.35***	***.12***	***1.62***	***3.40***
2021	***1.75***	***.40***	***.15***	***1.70***	***4.00***

Calendar	QUARTERLY DIVIDENDS PAID [B■†] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.405	.450	.450	.450	1.76
2017	.450	.495	.495	.495	1.94
2018	.495	.520	.520	.520	2.06
2019	.520	.545	.545	.545	2.16
2020	.545	.570			

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving about 2.1 million customers in parts of Arizona, Nevada, and California. Centuri provides construction services. 2019 margin mix: residential and small commercial, 84%; large commercial and industrial, 3%; transportation, 13%. Total throughput: 2.3 billion therms. Has 8,944 employees. Off. & dir. own .8% of common stock; BlackRock, Inc., 13.5%; The Vanguard Group, Inc., 10.3%; T.Rowe Price Assoc., Inc., 6.8% (3/20 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: John P. Hester. Inc.: DE. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas rebounded sharply in price in late March and early April. This followed a dramatic sell-off that began in late February, due to the spread of the coronavirus. The company reported mixed results for the March quarter. The top line advanced slightly for the period. Utility infrastructure revenue increased due to a higher volume of electric infrastructure and pipe replacement work under blanket and bid contracts. Performance at the utility was supported by customer growth and rate relief (which was mainly in California). Operating costs remained in check, and operating income of $148.4 million compared favorably with the prior-year figure of $140.5 million. However, earnings were hurt by a $15.5 million decline in the cash surrender value of company-owned life insurance policies, compared with an increase of $7.6 million in the year-ago period. As a result, earnings per share of $1.31 marked a significant decline, year over year.

Economic weakness associated with measures to curb the spread of the coronavirus pandemic will likely constrain performance in the near term. The economic impact of the pandemic ought to be more pronounced in the current quarter, and such challenges should remain in the back half of the year. The infrastructure services operation Centuri may be more affected than the utility business. In the long run, Centuri will probably benefit from the need for utilities to replace aging infrastructure. In the meantime, performance on the utility side should be supported by customer growth, infrastructure tracker mechanisms, expansion projects, and rate relief.

This stock is ranked to track the broader market averages for the coming six to 12 months. We anticipate solid bottom-line growth for Southwest out to early next decade. From the recent quotation, long-term appreciation potential is below average. Moreover, the dividend yield is not particularly generous for a utility. A selloff some time down the line may offer patient investors a better entry point. Southwest Gas earns good marks for Financial Strength, Price Stability, Growth Persistence, and Earnings Predictability. Volatility is subdued, as well.

Michael Napoli, CFA *May 29, 2020*

(A) Diluted earnings. Excl. nonrec. gains (losses): '05, (11¢); '06, 7¢. Next egs. report due early August. **(B)** Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions.
(D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	75
Earnings Predictability	95

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SPIRE INC. NYSE-SR

RECENT PRICE 71.77 | P/E RATIO 20.7 (Trailing: 24.3 Median: 18.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 11/30/18
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 5/1/20
BETA .80 (1.00 = Market)

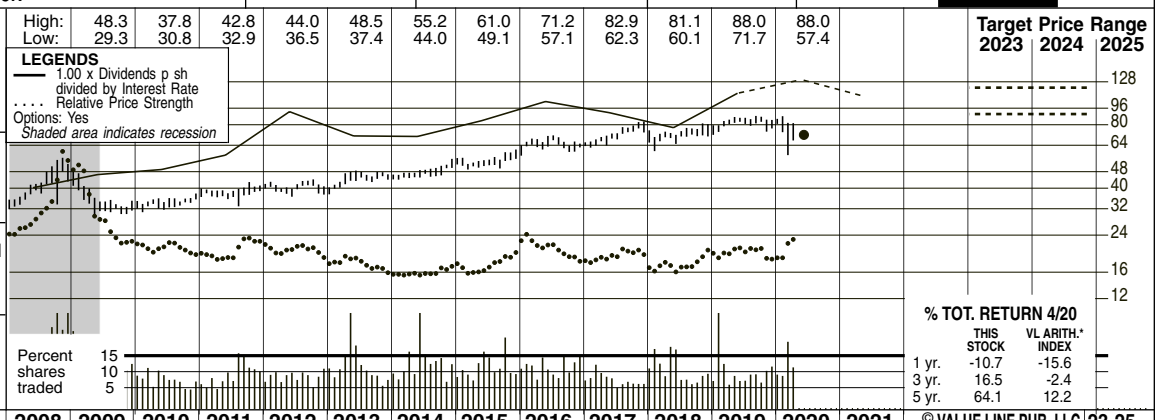
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$60-$125 $93 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+65%)	*16%*
Low	90	(+25%)	*9%*

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	116	115	127
to Sell	131	117	114
Hld's(000)	40622	41800	42195



2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	*35.60*	*37.25*	Revenues per sh A	*58.20*
2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	*7.10*	*7.70*	"Cash Flow" per sh	*9.75*
1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	*3.40*	*3.70*	Earnings per sh A B	*5.15*
1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	*2.49*	*2.61*	Div'ds Decl'd per sh C■	*3.00*
2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	*12.30*	*12.60*	Cap'l Spending per sh	*11.00*
16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	*54.00*	*59.05*	Book Value per sh D	*72.00*
20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	*52.00*	*52.50*	Common Shs Outst'g E	*55.00*
15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.5*
.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.24			Relative P/E Ratio	*1.15*
4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%			Avg Ann'l Div'd Yield	*2.9%*
1735.0	1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	*1850*	*1955*	Revenues ($mill) A	*3200*
54.0	63.8	62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	*175*	*195*	Net Profit ($mill)	*285*
33.4%	31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	32.4%	15.7%	*16.0%*	*17.0%*	Income Tax Rate	*23.5%*
3.1%	4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	*9.5%*	*10.0%*	Net Profit Margin	*8.9%*
40.5%	38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	*48.0%*	*47.0%*	Long-Term Debt Ratio	*45.0%*
59.5%	61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	55.0%	*52.0%*	*53.0%*	Common Equity Ratio	*55.0%*
899.9	937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	*5400*	*5850*	Total Capital ($mill)	*7200*
884.1	928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	*4740*	*5160*	Net Plant ($mill)	*6500*
7.4%	8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	*6.0%*	*6.5%*	Return on Shr. Equity	*7.0%*
10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	*6.0%*	*6.5%*	Return on Com Equity	*7.0%*
3.6%	4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	*1.5%*	*2.0%*	Retained to Com Eq	*3.0%*
64%	56%	59%	81%	73%	58%	59%	60%	51%	66%	*76%*	*72%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $3050.8 mill. **Due in 5 Yrs** $725.0 mill.
LT Debt $2484.8 mill. **LT Interest** $120.0 mill.
(Total interest coverage: 3.1x)

Leases, Uncapitalized Annual rentals $8.2 mill.
Pension Assets-9/19 $521.8 mill.
Oblig. $751.4 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $3.4 mill.
Common Stock 51,235,146 shs.
as of 5/5/20

MARKET CAP: $3.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	3/31/20
Cash Assets	4.4	5.8	108.4
Other	655.2	608.7	610.4
Current Assets	659.6	614.5	718.8
Accts Payable	290.1	301.5	221.4
Debt Due	729.1	783.2	566.0
Other	302.5	384.1	365.1
Current Liab.	1321.7	1468.8	1152.5
Fix. Chg. Cov.	284%	272%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-8.5%	-1.0%	*7.5%*
"Cash Flow"	5.5%	13.0%	*5.5%*
Earnings	3.5%	9.5%	*5.5%*
Dividends	4.0%	5.5%	*5.0%*
Book Value	7.0%	7.0%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	495.1	663.4	323.5	258.7	1740.7
2018	561.8	813.4	350.6	239.2	1965.0
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	*340*	*227.6*	*1850*
2021	*590*	*770*	*360*	*235*	*1955*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2017	.99	2.36	.45	d.28	3.43
2018	2.39	2.03	.52	d.51	4.33
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	*.37*	*d.75*	*3.40*
2021	*1.30*	*2.66*	*.45*	*d.71*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.49	.49	.49	.49	1.96
2017	.525	.525	.525	.525	2.10
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2019: 3.4 bill. Revenue mix for regulated operations: residential, 68%; commercial and industrial, 23%; transportation, 6%; other, 3%. Has about 3,536 employees. Officers and directors own 2.9% of common shares; BlackRock, 15.0% (1/20 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire Inc. has continued to underperform in fiscal 2020 (ends September 30th). In fact, first-half share net decreased 13.3%, to $3.78, compared to the prior-year total of $4.36. That was attributed largely to the Gas Marketing division, which recorded an unrealized loss of $0.29 a share on energy-related derivatives, while the fiscal 2019 amount included a $0.22 gain from that activity. Moreover, the Gas Utility segment generated modestly lower earnings.

Results for the second half ought to face some pressure from an extraordinary occurrence. Though the coronavirus had limited financial impact on the company during the first half, the situation now appears to be changing, given diminishing demand plus escalating bad debts and other operating costs. But Spire is pursuing operating efficiencies and potential regulatory mechanisms to help offset the impact. Consider, also, that the third quarter, fiscal 2019 loss of $0.09 a share should be easy to beat. Still, at this juncture, *Value Line* anticipates full-year profits of $3.40 a share, which would be 3% below the fiscal 2019 tally of $3.52. Regarding next year, however, a 9% rebound (to $3.70 a share) seems plausible, if the pandemic fades away.

The fiscal 2020 capital spending target was boosted by $30 million, to $640 million. That would still be substantially lower than last year's figure of $823 million, attributable, to a certain extent, to the completion of the Spire STL Pipeline. Funds are being deployed to such areas as infrastructure upgrades at the utilities and new business development initiatives. Leadership looks for total expenditures over the 2020-2024 horizon to be around $2.8 billion, which seems manageable.

These good-quality shares have not been invulnerable to the turbulence experienced by the market of late, reflecting worries about the virus. Even so, the dividend yield stacks up nicely to those of other equities in *Value Line's* Natural Gas Utility Industry. Moreover, our 2023-2025 projections show further steady hikes in the payout, which should continue to be well covered by earnings. Meanwhile, the stock is neutrally ranked for Timeliness.

Frederick L. Harris, III *May 29, 2020*

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '19: $1,171.6 mill., $22.99/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

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Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

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"Unusual and Exigent" Conditions Elicit Aggressive Policy Actions

- **Aggressive monetary policy actions involve Fed's balance sheet, not interest rates**
- **Fiscal policy actions make deficit four times the size forecast just two months ago**
- **Even as rates start to increase, they do so very slowly**
- **Long-term outlook just sees modest 2% growth and modest rise in interest rates**

In a 1935 amendment to the Federal Reserve Act of 1913, the Fed was enabled to extend credit to certain parties during "unusual and exigent circumstances." The current period is certainly "unusual." It is also "exigent," meaning, according to Merriam-Webster, that conditions "require immediate aid or action" and that they "require or call for much." In particular, the Fed's usual policy tool, the federal funds rate, was already cut to just above zero by mid-March, so the Federal Open Market Committee can't try to support the economy by lowering that unless they want to reconsider the view against negative interest rates.

Clearly, some policy action was needed. GDP dropped at a 5% annual rate in Q1 and is estimated by the Blue Chip panel to plunge at a 34.0% rate this quarter. A turnaround toward a 15% rate of growth is expected in Q3.

Fed balance sheet already up by $2.94 trillion. So in response to this perceived need for creative policy actions, the Fed has established nine credit-granting facilities reaching out to, as the descriptions all say, "households and businesses." And, as well, to state and local governments. In each case, the Fed is not the actual lender to the actual user of the funds, but it supports, among others, financial institution lenders such as commercial paper issuers (CPFF), money market mutual funds (MMLF) and the well-known Paycheck Protection Program Liquidity Facility (PPPLF) for small businesses. These programs began in late March and most recently have totaled some $130 billion. Since mid-March, the Fed has also bought $1.6 trillion in U.S. Government securities and its total assets have grown from $4.16 trillion to $7.10 trillion.

While the special programs cover just a fraction of the increase in the Fed's assets and a fraction of their legislated totals, they have carried larger announcement effects than the actual dollar amounts might imply. Fed Vice Chair Richard Clarida commented on this in a speech May 21; "just the announcement that these backstop facilities would soon be launched appears to have bolstered confidence in capital markets, allowing many companies to finance themselves privately even before the facilities were up and running."

Fed needs to pair with fiscal policy to give economy effective help. One other clarification on the role of legislation in these Federal Reserve actions. Vice Chair Clarida made a helpful point: ". . . it is important to note that the Fed's statutory authority grants us *lending* powers, not *spending* powers. The Fed is not authorized to grant money to particular beneficiaries, to meet the payroll expenses of small businesses, or to underwrite the unemployment benefits of displaced workers. Programs to support such worthy goals reside squarely in the domain of fiscal policy. The Fed can only make loans to solvent entities with the expectation the loans will be paid back. Direct fiscal support for the economy is thus also essential to sustain economic activity and complement what monetary policy cannot accomplish on its own."

The Blue Chip Financial Forecasts panel believes the Fed's total assets will reach $9.4 trillion at the end of this year, so it would acquire another $2.3 trillion in securities and special facilities loans. At the end of 2021, the panel estimates a balance sheet of $10.2 trillion, with a few of the panelists actually looking for reductions in the Fed's total assets.

Aggressive fiscal policy as well. Fiscal policy actions include the coordination with the Federal Reserve funded programs as well as some other CARES Act benefits, special exemptions on the SNAP food stamps program, more funding for COVID-19 testing, increased funding for certain small business grants and so on. Before all this was enacted during March and April, the March 1st issue of Blue Chip Financial Forecasts included a Special Question asking for panelists' budget deficit estimate for fiscal 2020. They said then that after the $984 billion in fiscal 2019, the fiscal 2020 deficit would be $1.077 trillion. Now the panel is saying $4.0 trillion this fiscal year and $2.5 trillion in fiscal 2021.

As to the more standard interest rate forecasts, the panel expects that the Fed would hold the federal funds rate at its current almost-zero level until the middle of next year, when it would start to raise rates. Even then, the increase in Q3 2021 would still be quite modest, with just a dozen members of the Blue Chip panel seeing the rate higher than it has been recently and most of those by only a token amount. Other interest rates would rise somewhat more over the forecast span to Q3 2021, with ten-year Treasuries moving from their recent yield of 66 basis points to 1.2% by Q3 2021. Thus, the yield curve would steepen somewhat.

Long-term forecasts see growth, inflation and funds rate centering on 2%. This month's Financial Forecasts survey includes the semi-annual look at long-term trends in rates. GDP growth starts this coming decade slightly stronger at 3.2% in 2021 and 2022, and then moderates to 2.0% by 2026. Over the following five years it would average 2.1% a year. Inflation, measured by the CPI, would be 0.2% across this year, Q4 over Q4, then climb to 1.3% next year and 2.1% across the next five years and 2.2% the five years after that.

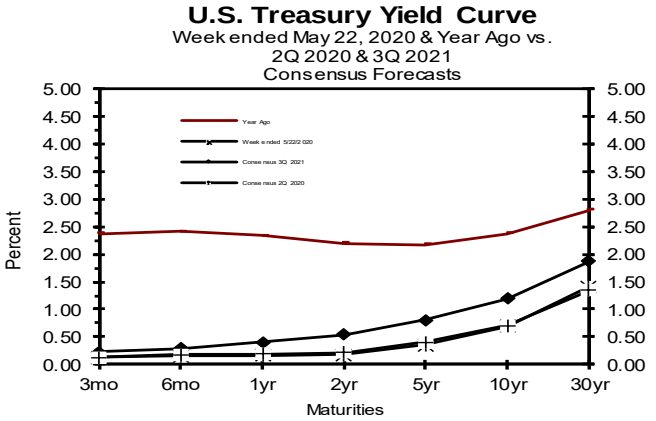
The fed funds rate would climb gradually toward 2%, reaching that between 2025 and 2026, and then hover just above that level during the following five years. Ten-year Treasury yields would increase from an average of 0.93% this year toward 1.2% next year, with averages of 2.3% and 3.1% during the two succeeding five-year periods. The pattern traced by these projections suggests that the aftermath of the current exigent economic conditions might take at least a couple of years to settle out and only further into the 2020s decade would the economy settle into a more orderly and sustainable situation.

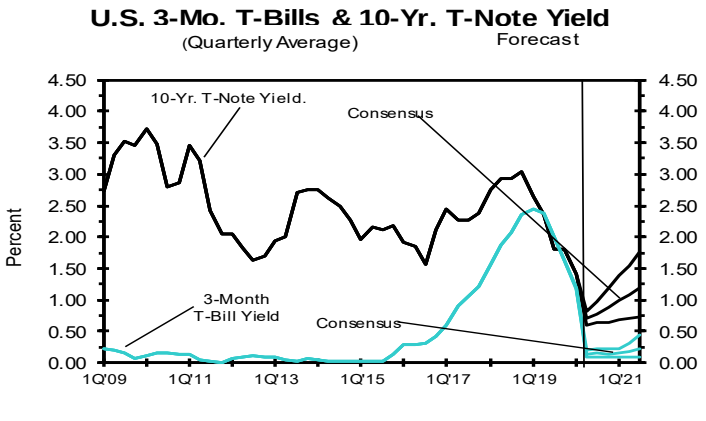
Carol Stone, CBE (Haver Analytics, New York, NY)

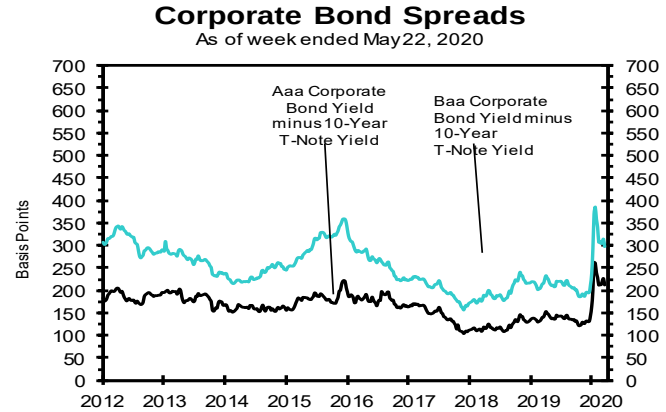
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

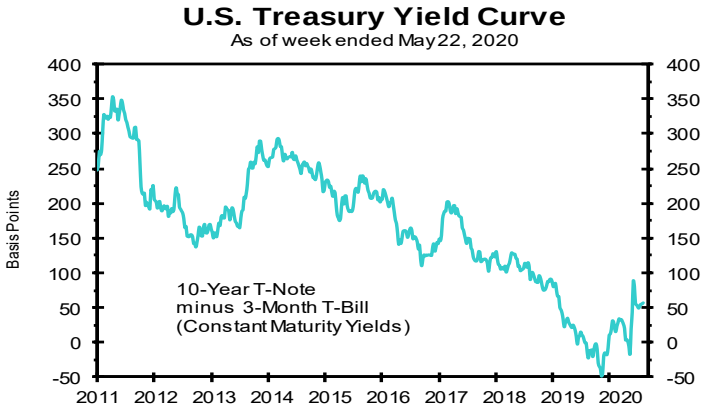
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 22	May 15	May 8	May 1	Apr	Mar	Feb	1Q 2020	2020	2020	2020	2021	2021	2021
Federal Funds Rate	0.05	0.05	0.05	0.04	0.05	0.65	1.58	1.26	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.78	4.75	4.43	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**
LIBOR, 3-mo.	0.37	0.40	0.46	0.68	1.09	1.10	1.68	1.53	**0.7**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**
Commercial Paper, 1-mo.	0.14	0.12	0.14	0.19	0.47	1.36	1.55	1.49	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**
Treasury bill, 3-mo.	0.12	0.12	0.12	0.11	0.14	0.30	1.54	1.13	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Treasury bill, 6-mo.	0.15	0.15	0.15	0.13	0.17	0.30	1.51	1.12	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**
Treasury bill, 1 yr.	0.16	0.15	0.16	0.17	0.18	0.33	1.41	1.09	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Treasury note, 2 yr.	0.17	0.16	0.17	0.21	0.22	0.45	1.33	1.10	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**
Treasury note, 5 yr.	0.35	0.33	0.34	0.37	0.39	0.59	1.32	1.16	**0.4**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**
Treasury note, 10 yr.	0.69	0.67	0.67	0.64	0.66	0.87	1.50	1.38	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**
Treasury note, 30 yr.	1.41	1.36	1.34	1.25	1.27	1.46	1.97	1.88	**1.4**	**1.5**	**1.5**	**1.7**	**1.8**	**1.9**
Corporate Aaa bond	2.82	2.94	2.89	2.77	2.86	3.11	2.85	3.00	**2.5**	**2.6**	**2.7**	**2.7**	**2.8**	**2.9**
Corporate Baa bond	3.66	3.81	3.74	3.68	3.87	4.11	3.50	3.76	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.3**
State & Local bonds	3.26	3.37	3.46	3.50	3.41	3.29	2.93	3.07	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**
Home mortgage rate	3.24	3.28	3.26	3.23	3.31	3.45	3.47	3.51	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2018	2018	2018	2019	2019	2019	2019	2020	2020	2020	2020	2021	2021	2021
Fed's AFE $ Index	105.5	107.8	109.4	109.4	110.3	110.5	110.3	111.2	**113.2**	**113.6**	**113.6**	**113.4**	**112.9**	**112.4**
Real GDP	3.5	2.9	1.1	3.1	2.0	2.1	2.1	-5.0	**-34.0**	**15.2**	**8.2**	**6.2**	**4.7**	**3.7**
GDP Price Index	3.2	2.0	1.6	1.1	2.4	1.8	1.3	1.4	**-0.4**	**1.0**	**1.3**	**1.5**	**1.7**	**1.7**
Consumer Price Index	2.2	2.1	1.3	0.9	3.0	1.8	2.4	1.2	**-3.2**	**1.3**	**1.7**	**2.1**	**1.9**	**1.9**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).









----------Policy Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.13	0.13	2.38	**0.12**	**0.12**	**0.13**
Japan	-0.10	-0.10	-0.10	**-0.09**	**-0.09**	**-0.09**
U.K.	0.10	0.10	0.75	**0.10**	**0.09**	**0.09**
Switzerland	-0.75	-0.75	-0.75	**-0.75**	**-0.75**	**-0.75**
Canada	0.25	0.25	1.75	**0.23**	**0.25**	**0.25**
Australia	0.25	0.25	1.50	**0.25**	**0.25**	**0.29**
Euro area	0.00	0.00	0.00	**0.00**	**0.00**	**0.00**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.66	0.60	2.32	**0.73**	**0.78**	**0.92**
Germany	-0.49	-0.47	-0.12	**-0.45**	**-0.39**	**-0.29**
Japan	0.00	-0.02	-0.07	**-0.05**	**-0.07**	**-0.07**
U.K.	0.21	0.32	1.03	**0.31**	**0.39**	**0.55**
France	-0.04	0.03	0.28	**-0.05**	**-0.04**	**0.04**
Italy	1.62	1.84	2.55	**1.72**	**1.63**	**1.61**
Switzerland	-0.51	-0.43	-0.38	**-0.58**	**-0.53**	**-0.49**
Canada	0.51	0.58	1.61	**0.70**	**0.75**	**0.96**
Australia	0.87	0.88	1.52	**0.91**	**0.87**	**0.91**
Spain	0.68	1.01	0.83	**0.72**	**0.73**	**0.74**

----------Foreign Exchange Rates[3]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	113.50	114.04	110.72	**114.4**	**114.5**	**112.6**
Japan	107.50	107.44	109.38	**107.6**	**108.2**	**109.1**
U.K.	1.22	1.23	1.27	**1.22**	**1.23**	**1.26**
Switzerland	0.97	0.98	1.00	**0.97**	**0.96**	**0.96**
Canada	1.40	1.41	1.35	**1.41**	**1.40**	**1.37**
Australia	0.65	0.64	0.69	**0.64**	**0.64**	**0.66**
Euro	1.09	1.08	1.12	**1.09**	**1.10**	**1.12**

	Consensus Policy Rates vs. US Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-0.23	**-0.22**	Germany	-1.15	**-1.21**
U.K.	-0.03	**-0.03**	Japan	-0.66	**-0.98**
Switzerland	-0.88	**-0.88**	U.K.	-0.45	**-0.37**
Canada	0.13	**0.13**	France	-0.70	**-0.88**
Australia	0.13	**0.16**	Italy	0.96	**0.69**
Euro area	-0.13	**-0.13**	Switzerland	-1.17	**-1.40**
			Canada	-0.15	**0.04**
			Australia	0.21	**-0.01**
			Spain	0.02	**-0.18**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International Since the middle of March when the coronavirus outbreak turned into a pandemic and large parts of economies were shut down, the Fed has increased its balance sheet by nearly $2.8 trillion, or 65%, to just over $7 trillion. Other major central banks have followed the Fed's aggressive lead. The European Central Bank has also restarted its asset purchase program and created a new one specially to confront the pandemic—the Pandemic Emergency Purchase Program (PEPP), which is scheduled to purchase €750 billion of assets by the end of this year. Since PEPP purchases were initiated at the beginning of April, the ECB has bought €212 billion of securities and has purchased another €107 billion in its APP (restarted in mid-March), increasing the ECB's assets by 18% to 46% of 2020 Q1 euro area GDP. Analysts generally expect the ECB to increase and to extend the PEPP at its June 4 Council meeting.

In mid-March, the Bank of England's Monetary Policy Committee voted unanimously to increase the Bank's holdings of UK government bonds and sterling non-financial investment-grade corporate bonds by £200 billion to a total of £645 billion. Since then, it has purchased nearly £126 billion of new securities. The Bank of England's external forecasters expect the Bank's total holdings to be increased to nearly £700 billion by the second quarter of 2021. The Bank of Japan has also increased its ongoing asset purchase program and created several new lending facilities. The most recent one aimed at increasing credit flow to small and medium-sized business was announced after an emergency meeting on May 22. Since the middle of March, the BoJ's assets have risen ¥43 trillion to 116% of Q1 nominal GDP.

Two central banks that had eschewed quantitative easing during the global financial crisis, the Reserve Bank of Australia and the Bank of Canada, have recently started asset purchase programs and have been quite aggressive. The RBA's program is similar to the Bank of Japan's yield curve control. The RBA intends to buy sufficient government and semi-government bonds to stabilize the yield on the 3-year government bond at 0.25%. Since mid-March, the Bank has increased its assets by 44%, buying A$111 billion of securities. Over this period the 3-year government bond yield has averaged 0.26% versus 0.64% during the first 2-1/2 months of 2020.

At the beginning of April, the Bank of Canada embarked on an asset purchasing campaign in which it intends to buy C$5 billion of Canadian government securities per week "until the economic recovery is well under way." So far, the Bank has purchased nearly C$50 billion of government bonds though its overall balance sheet has increased by much more—C$288 billion, a 187% increase—as repos and purchases of other securities have soared.

As the economic costs of the lockdowns escalate by unprecedented magnitudes, monetary policymakers have appealed for more fiscal support. The US government has legislated more than $2.7 trillion in aid and programs aimed at reducing the economic hit from the pandemic and the House has passed another $3 trillion package. Led by the fiscal authorities in Germany and France, individual euro area governments have also enacted aid programs totaling billions of euros. However, the most significant euro area fiscal policy response would be the €1.85 trillion coronavirus response plan recently proposed by the European Union. The proposal is composed of a €750 billion immediate recovery plan and an additional €1.1 trillion of economic activity-boosting budget over the next seven years. The proposal's largest hurdle is that it must be accepted by all 27 EU members, which at the very least would take some time. But if that can be accomplished, this would be a major step toward increased fiscal union across the bloc. Japan's fiscal policymakers have recently taken a more concrete step. In late May the Cabinet approved a second supplemental budget, which should be legislated sometime in June. This supplemental budget is estimated at slightly more than 6% of GDP on top the 5% of GDP supplemental budget passed in late April. Nearly half of the new supplement is earmarked for support to business.

Second Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term			Long-Term								
J.P. Morgan Chase	0.3 H	na	0.9	na	na	na	na	0.5 H	0.6 H	0.9	1.6	na	na	na	na	na	-40.0	-2.0	-3.9
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.3	0.5	0.8	1.3	na	na	na	na	na	-39.0	1.7	-2.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.3	na	na	na	3.3	na	-27.7	na	-4.1
Via Nova Investment Mgt.	0.2	3.3 H	0.8	0.2	0.1	0.1	0.1	0.2	0.4	0.7	1.3	2.9	4.2	1.6	3.2	112.8	-20.0	-1.0	-4.0
ACIMA Private Wealth	0.1	3.3 H	1.0	1.4	0.1	0.2	0.2	0.2	0.3	0.7	1.4	2.5	4.2	2.4	3.7 H	113.0	-40.0	1.3	1.5
Action Economics	0.1	3.3 H	1.5 H	0.2	0.1	0.1	0.1	0.2	0.4	0.7	1.4	2.4	3.8	2.7	3.5	111.3	-38.0	-2.8	-3.9
Amherst Pierpont Securities	0.1	3.3 H	0.6	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.5	4.1	2.5	3.3	113.5	-32.0	1.5	-3.2
Bank of America	0.1	na	0.6	na	na	na	na	0.2	0.3	0.5 L	1.0 L	na	na	na	na	na	-40.0	-1.0	-3.2
Barclays	0.1	3.3 H	na	na	na	na	na	0.2	0.5	0.7	1.4	na	na	na	na	na	-40.0	-2.7	-3.9
BMO Capital Markets	0.1	3.3 H	0.7	na	0.1	0.2	0.2	0.2	0.4	0.7	1.3	na	na	na	3.2	114.3 H	-40.0	-2.0	-3.9
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.3	na	0.8	na	na	na	na	na	na	-40.0	na	-4.1
Chan Economics	0.1	3.3 H	0.8	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.5	-35.0	1.9	2.0 H
Chmura Economics & Analytics	0.1	3.3 H	0.7	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	na	na	3.3	na	-18.4	1.0	1.2
Comerica Bank	0.1	3.2	0.7	na	0.1	0.2	0.2	0.2	0.4	0.7	1.3	na	na	na	3.1	na	-28.3	-0.1	-4.4
Daiwa Capital Markets America	0.1	3.3 H	0.9	0.1 L	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.6	4.1	na	3.3	114.0	-38.4	0.5	-3.2
DePrince & Assoc.	0.1	3.3 H	0.6	0.3	0.1	0.2	0.2	0.2	0.3	0.7	1.3	2.6	4.1	2.5	3.2	113.2	-17.6 H	-1.7	-1.8
Fannie Mae	0.1	3.3 H	na	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	na	na	na	3.3	na	-36.6	-0.9	-3.3
Georgia State University	0.1	3.3 H	na	na	0.0 L	0.0 L	0.0 L	0.1	0.4	0.7	1.3	2.9	4.5	na	3.4	na	-41.8	-1.0	-3.3
GLC Financial Economics	0.1	3.3 H	0.5	0.2	0.1	0.1	0.2	0.2	0.4	0.6	1.3	2.8	4.0	2.8	3.4	109.4 L	-32.7	0.0	-1.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	0.2	0.3	0.6	1.1	na	na	na	3.2	na	-39.0	-0.2	-4.9
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3 L	0.3	0.2	0.2	0.2	0.2	0.4	0.7	1.3	2.0	4.4	na	3.3	na	-35.7	-1.0	-3.2
Loomis, Sayles & Company	0.1	3.3 H	0.6	0.2	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.6	3.8	3.3	3.3	113.1	-40.0	-1.1	-4.0
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.4	0.1 L	0.1	0.2	0.2	0.2	0.4	0.6	1.4	2.7	3.7	2.8	3.3	113.8	-35.5	1.0	-3.3
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.6	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.1 L	1.0	0.3	0.4 H	0.4 H	0.4 H	0.4	0.5	0.6	1.5	2.5	4.2	2.6	3.2	na	-32.7	2.1 H	-3.9
Moody's Capital Markets Group	0.1	3.3 H	0.6	0.3	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	4.0	3.0	3.3	114.0	-33.5	-0.5	-4.3
MUFG Union Bank	0.1	3.3 H	0.6	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.4	3.9	2.8	3.3	113.5	-30.0	1.5	-3.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6 H	0.1	0.1	0.2	0.2	0.4	0.7	1.2	2.1	4.1	2.3	3.3	114.0	-22.0	0.8	-1.2
NatWest Markets	0.1	3.3 H	0.7	0.4	0.2	0.2	0.2	0.2	0.4	0.7	1.5	2.8	3.6	3.5 H	3.2	113.5	-35.6	-2.0	-4.0
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.3	0.4	0.6	na	na	na	na	na	na	-49.2 L	1.7	-3.5
Oxford Economics	0.1	3.3 H	1.1	na	0.1	0.2	0.2	0.3	0.4	0.6	1.5	1.6 L	na	na	3.3	114.3 H	-36.6	-3.9 L	-6.5 L
PNC Financial Services Corp.	0.1	3.3 H	0.6	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	na	4.1	0.7 L	3.3	na	-30.1	-0.3	-5.8
RDQ Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.2	0.2	0.2	0.5	0.7	1.3	2.4	3.7	3.1	3.4	113.2	-34.7	1.0	-3.5
Regions Financial Corporation	0.1	3.3 H	0.6	na	0.1	0.2	0.2	0.2	0.4	0.7	1.4	2.7	4.2	2.6	3.4	113.6	-36.2	1.9	-4.7
S&P Global	0.1	3.3 H	1.0	na	0.0 L	0.0 L	0.0 L	0.0 L	0.4	0.7	1.4	na	na	na	3.3	na	-34.6	-2.1	-1.4
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.2	0.4	0.7	1.4	na	na	na	na	na	-30.0	0.8	-3.5
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6 H	1.0 H	1.7 H	3.4 H	5.4 H	na	2.7 L	na	-39.5	na	-4.0
The Northern Trust Company	0.1	3.2	0.6	0.2	0.1	0.2	0.2	0.2	0.4	0.7	1.3	2.5	3.6	3.4	3.3	113.5	-36.5	-2.1	-3.0
TS Lombard	0.1	3.2	0.4	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.4	2.1	3.1 L	1.3	2.7 L	113.3	-23.0	-3.0	-5.0
Wells Fargo	0.1	3.3 H	0.3 L	0.1 L	0.1	0.2	0.2	0.2	0.4	0.8	1.4	2.0	3.7	1.9	3.3	na	-24.7	-1.3	-4.0
ING	0.0 L	na	0.4	na	na	na	na	0.0 L	0.2 L	1.0 H	1.0 L	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.7**	**0.3**	**0.1**	**0.2**	**0.2**	**0.2**	**0.4**	**0.7**	**1.4**	**2.5**	**4.0**	**2.5**	**3.3**	**113.2**	**-34.0**	**-0.4**	**-3.2**
Top 10 Avg.	0.2	3.3	1.0	0.6	0.2	0.2	0.2	0.3	0.5	0.8	1.5	2.8	4.4	3.0	3.4	113.9	-24.2	1.6	-0.9
Bottom 10 Avg.	0.1	3.3	0.4	0.2	0.1	0.1	0.1	0.2	0.3	0.6	1.2	2.2	3.7	2.0	3.1	112.6	-41.1	-2.4	-4.8
May Consensus	0.1	3.3	0.9	0.4	0.1	0.1	0.2	0.2	0.4	0.7	1.3	2.6	4.3	2.6	3.3	113.5	-27.8	0.1	-2.4
Number of Forecasts Changed From A Month Ago:																			
Down	3	2	16	11	5	3	5	14	8	6	2	9	10	6	11	9	25	20	19
Same	36	27	9	6	23	22	21	22	25	25	19	8	6	7	14	6	10	12	9
Up	2	4	4	5	6	7	5	4	6	10	17	8	8	7	7	4	4	4	11
Diffusion Index	49%	53%	29%	36%	51%	56%	50%	38%	47%	55%	70%	48%	46%	53%	44%	37%	23%	28%	40%

Third Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.2	0.4	0.7	1.5	na	na	na	na	na	23.0	1.8	2.0
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.4 H	0.6 H	0.9	1.5	na	na	na	na	na	25.9	-0.2	-1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.8	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	114.0	5.0	0.0	-1.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.1	0.2 H	0.2	0.2	0.3 L	0.6	1.3	na	na	na	3.3	na	13.8	na	0.4
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.5	0.1	0.1	0.1	0.2	0.4	0.8	1.5	2.8	4.7	2.6	4.0 H	114.0	18.0	1.1	-5.0 L
Action Economics	0.1	3.3 H	0.5	0.2	0.1	0.2 H	0.2	0.4 H	0.6 H	0.9	1.6	2.3	3.5	3.0	3.6	113.6	28.0	1.7	1.2
Amherst Pierpont Securities	0.1	3.3 H	0.4	0.1 L	0.2	0.2 H	0.3	0.4 H	0.6 H	1.0	1.7 H	2.8	4.3	2.8	3.6	114.0	28.0	2.0	3.5
Bank of America	0.1	na	0.5	na	na	na	na	0.3	0.4	0.6	1.2	na	na	na	na	na	7.0	1.6	2.9
Barclays	0.1	3.3 H	na	na	na	na	na	0.2	0.5	0.8	1.5	na	na	na	na	na	25.0	2.0	2.5
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2 H	0.2	0.3	0.5	0.8	1.5	na	na	na	3.0	115.1 H	43.0 H	1.4	2.1
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.4 H	na	1.0	na	na	na	na	na	na	22.2	na	1.2
Chan Economics	0.1	3.3 H	0.7	0.4	0.1	0.2 H	0.2	0.2	0.3 L	0.6	1.3	2.6	4.6	2.6	3.3	113.7	6.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.6	0.1 L	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.6	na	na	3.3	na	1.0	1.2	1.2
Comerica Bank	0.1	3.2 L	0.5	na	0.1	0.2 H	0.2	0.2	0.5	0.7	1.5	na	na	na	3.1	na	12.1	1.0	2.1
Daiwa Capital Markets America	0.1	3.3 H	0.6	0.2	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.5	4.1	na	3.3	114.0	8.5	1.0	1.5
DePrince & Assoc.	0.1	3.3 H	0.3 L	0.3	0.1	0.1	0.1	0.2	0.3 L	0.7	1.4	2.9	4.0	2.6	3.1	112.6	2.5	0.6	0.7
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2 H	0.2	0.2	0.4	0.7	1.5	na	na	na	3.2	na	18.4	1.3	1.6
Georgia State University	0.1	3.3 H	na	na	0.0 L	-0.1 L	0.0 L	0.1 L	0.4	0.7	1.4	3.3	4.6	na	3.5	na	3.4	1.6	2.3
GLC Financial Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	3.0	4.2	3.0	3.6	110.1 L	-18.9 L	0.9	1.1
Goldman Sachs & Co.	0.1	na	na	na	0.5 H	na	na	0.2	0.4	0.5 L	1.0 L	na	na	na	2.8	na	29.0	2.7 H	1.4
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3 L	0.3	0.2	0.2 H	0.3	0.4 H	0.5	0.7	1.4	2.1	2.6 L	na	3.3	na	7.6	2.4	3.0
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.2 H	0.2	0.2	0.3 L	0.7	1.4	2.6	3.7	2.9	3.2	113.1	9.3	1.4	2.0
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.4	0.2	0.2	0.2 H	0.3	0.3	0.4	0.7	1.4	2.7	3.9	3.0	3.4	114.0	-1.0	1.2	2.5
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.7	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.9	0.1 L	0.2	0.2 H	0.4 H	0.4 H	0.5	0.6	1.7 H	2.8	4.3	2.6	3.1	na	16.2	-2.1 L	1.4
Moody's Capital Markets Group	0.1	3.3 H	0.5	0.2	0.1	0.2 H	0.2	0.2	0.4	0.7	1.3	2.5	4.0	3.0	3.3	114.6	15.7	0.9	1.3
MUFG Union Bank	0.1	3.3 H	0.3 L	na	0.1	0.2 H	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.8	3.2	114.0	15.0	1.5	2.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6 H	0.1	0.1	0.2	0.3	0.5	0.7	1.3	2.2	4.1	2.4	3.4	114.0	6.0	1.0	0.8
NatWest Markets	0.1	3.2 L	0.6	0.4	0.1	0.2 H	0.2	0.3	0.4	0.8	1.5	2.9	3.8	3.3	3.1	111.0	20.2	1.4	2.9
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.4 H	0.5	0.7	na	na	na	na	na	na	30.0	1.5	1.5
Oxford Economics	0.1	3.3 H	0.6	na	0.2	0.2 H	0.2	0.3	0.5	0.8	1.7 H	1.8 L	na	na	3.3	115.1 H	27.0	1.1	0.4
PNC Financial Services Corp.	0.1	3.3 H	0.3 L	na	0.1	0.2 H	0.2	0.2	0.4	0.7	1.5	na	4.1	0.8 L	3.2	na	12.6	-1.5	-0.5
RDQ Economics	0.1	3.3 H	0.3 L	0.2	0.1	0.2 H	0.2	0.2	0.6 H	0.9	1.6	2.6	3.9	3.4 H	3.4	114.3	12.2	2.7 H	3.6
Regions Financial Corporation	0.1	3.3 H	0.4	na	0.2	0.2 H	0.2	0.2	0.4	0.8	1.5	2.7	4.3	2.6	3.4	113.8	22.3	-0.5	3.9 H
S&P Global	0.1	3.3 H	0.6	na	0.2	0.2 H	0.2	0.3	0.6 H	1.0	1.7 H	na	na	na	3.5	na	24.1	-1.5	0.3
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.3	0.4	0.7	1.4	na	na	na	na	na	15.0	1.7	1.0
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2 H	0.3	0.4 H	0.6 H	1.0	1.7 H	3.4 H	5.7 H	na	2.7	na	25.0	na	0.6
The Northern Trust Company	0.1	3.3 H	0.6	0.2	0.2	0.2 H	0.2	0.3	0.5	0.8	1.4	2.5	3.6	3.2	3.1	112.5	18.4	0.6	0.5
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.2 H	0.2	0.2	0.3 L	0.6	1.3	2.0	3.0	1.2	2.6 L	115.0	9.5	0.5	-1.0
Wells Fargo	0.1	3.3 H	0.3 L	0.1 L	0.1	0.2 H	0.2	0.3	0.5	1.0	1.7 H	2.3	3.8	2.1	3.3	na	6.7	1.0	1.5
ING	0.0 L	na	0.4	na	na	na	na	0.2	0.4	1.3 H	1.3	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.3**	**0.1**	**0.2**	**0.2**	**0.3**	**0.4**	**0.8**	**1.5**	**2.6**	**4.0**	**2.6**	**3.3**	**113.6**	**15.2**	**1.0**	**1.3**
Top 10 Avg.	0.2	3.3	0.8	0.6	0.2	0.2	0.3	0.4	0.6	1.0	1.6	3.0	4.5	3.0	3.5	114.4	28.5	2.1	2.9
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.6	1.3	2.3	3.6	2.1	3.0	112.8	1.8	-0.3	-0.6
May Consensus	0.1	3.3	0.7	0.4	0.1	0.2	0.2	0.3	0.5	0.8	1.4	2.7	4.3	2.6	3.3	113.5	7.4	1.1	1.1
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	12	6	2	3	6	10	11	8	3	8	10	6	5	7	8	11	12
Same	38	29	15	13	27	23	21	28	25	24	18	8	6	6	16	6	8	13	11
Up	2	4	2	3	5	6	4	2	3	9	17	9	8	8	11	6	23	12	16
Diffusion Index	51%	56%	33%	43%	54%	55%	47%	40%	40%	51%	68%	52%	46%	55%	59%	47%	69%	51%	55%

Fourth Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term			Long-Term								
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.2	0.5	0.9	1.6	na	na	na	na	na	10.0	1.8	1.2
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.6	0.9	1.1	1.7	na	na	na	na	na	16.3	-0.7	1.0
Via Nova Investment Mgt.	0.3 H	3.3 H	0.7	0.3	0.2	0.1	0.1	0.3	0.4	0.7	1.3	2.9	4.2	1.6	3.2	113.0	15.0	1.0	1.5
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.4	na	na	na	3.4	na	9.1	na	2.5
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.8 H	0.1	0.1	0.1	0.2	0.5	0.9	1.7	2.9	5.1	2.8	4.3 H	115.0	-2.0	1.0	-1.1 L
Action Economics	0.1	3.3 H	0.5	0.3	0.1	0.2	0.3	0.4	0.7	0.9	1.6	2.3	3.4	3.0	3.7	113.7	13.0	2.1	1.5
Amherst Pierpont Securities	0.1	3.3 H	0.5	0.1 L	0.2	0.3 H	0.4 H	0.8 H	1.0 H	1.4 H	2.1 H	3.2	4.6	3.1	3.9	114.5	7.1	2.2	2.8
Bank of America	0.1	na	0.5	na	na	na	na	0.5	0.7	1.0	1.6	na	na	na	na	na	12.0	0.7	0.1
Barclays	0.1	3.3 H	na	na	na	na	na	0.3	0.6	0.9	1.6	na	na	na	na	na	8.0	1.9	2.0
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2	0.3	0.4	0.6	0.9	1.5	na	na	na	2.8	114.4	5.0	1.7	2.0
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.5	na	1.3	na	na	na	na	na	na	10.0	na	1.7
Chan Economics	0.1	3.3 H	0.7	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.8	10.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.6	0.2	0.1	0.2	0.2	0.3	0.6	0.9	1.5	2.7	na	na	3.3	na	4.4	1.8	1.8
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	3.0	na	-2.6 L	1.3	1.3
Daiwa Capital Markets America	0.1	3.3 H	0.5	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.5	2.6	4.1	na	3.3	114.0	15.5	1.3	2.0
DePrince & Assoc.	0.1	3.3 H	0.4	0.3	0.1	0.1	0.1	0.2	0.3	0.8	1.4	3.0	4.0	2.6	3.0	111.9	6.7	1.2	1.2
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2	0.2	0.2	0.4	0.7	1.5	na	na	na	3.1	na	12.6	0.8	2.4
Georgia State University	0.1	3.3 H	na	na	-0.1 L	-0.2 L	0.0 L	0.1	0.5	0.9	1.6	3.6 H	4.8	na	3.6	na	1.0	1.8	2.2
GLC Financial Economics	0.1	3.3 H	0.3	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.4	2.9	4.2	2.9	3.6	110.0	4.1	1.8	2.0
Goldman Sachs & Co.	0.1	na	na	na	0.4 H	na	na	0.3	0.5	0.7	1.2 L	na	na	na	2.9	na	11.0	1.8	2.7
Grant Thornton/Diane Swonk	0.1	3.3 H	0.4	0.3	0.2	0.2	0.1	0.0 L	0.1 L	0.5 L	1.2 L	1.9 L	2.8	na	3.0	na	3.4	1.3	3.0
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.1	0.2	0.2	0.3	0.8	1.4	2.5	3.5	2.6	3.1	112.9	11.2	0.6	1.9
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	3.9	3.0	3.4	114.4	6.5	1.4	2.1
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.2	0.2	0.4 H	0.5	0.6	0.7	1.9	2.5	3.9	2.4	3.1	na	0.6	1.0	2.8
Moody's Capital Markets Group	0.1	3.3 H	0.6	0.3	0.1	0.1	0.2	0.2	0.3	0.7	1.3	2.5	3.9	3.0	3.3	115.2	7.6	1.4	1.9
MUFG Union Bank	0.1	3.3 H	0.2 L	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.8	3.2	115.0	7.0	1.5	2.1
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6	0.1	0.2	0.2	0.3	0.6	0.9	1.5	2.3	4.0	2.5	3.5	113.0	4.4	1.2	1.0
NatWest Markets	0.1	3.2 L	0.5	0.3	0.1	0.2	0.3	0.3	0.5	1.0	1.6	3.0	4.0	3.1	3.2	109.0 L	8.4	1.5	1.6
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.4	0.6	0.8	na	na	na	na	na	na	5.2	1.5	-0.6
Oxford Economics	0.1	3.3 H	0.4	na	0.2	0.2	0.2	0.3	0.7	1.1	1.8	2.0	na	na	3.3	115.1	11.0	2.3 H	2.0
PNC Financial Services Corp.	0.1	3.3 H	0.2 L	na	0.1	0.2	0.2	0.2	0.4	0.8	1.5	na	4.2	0.9 L	3.2	na	9.0	-0.9 L	0.4
RDQ Economics	0.1	3.3 H	0.3	0.2	0.1	0.2	0.2	0.2	0.7	1.1	1.9	2.7	4.0	3.6 H	3.4	113.8	9.6	2.3 H	2.5
Regions Financial Corporation	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.3	0.5	0.9	1.6	2.8	4.4	2.7	3.5	114.1	6.0	1.5	2.3
S&P Global	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.0	na	na	na	3.6	na	17.6 H	0.4	1.6
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.4	0.5	0.7	1.4	na	na	na	na	na	7.0	1.0	1.2
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.4	5.3 H	na	2.7	na	15.1	na	3.4 H
The Northern Trust Company	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.4	0.5	0.8	1.4	2.4	3.4	3.0	2.9	111.5	13.2	0.9	1.0
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.2	0.2	0.2	0.3	0.5 L	1.2 L	1.9 L	2.7 L	1.1	2.5 L	118.0 H	5.0	0.8	0.0
Wells Fargo	0.1	3.3 H	0.3	0.1 L	0.1	0.2	0.2	0.4	0.7	1.2	1.9	2.5	3.8	2.3	3.3	na	4.4	1.7	2.4
ING	0.0 L	na	0.4	na	na	na	na	0.3	0.5	1.4 H	1.4	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.1**	**0.2**	**0.2**	**0.3**	**0.5**	**0.9**	**1.5**	**2.7**	**4.0**	**2.6**	**3.3**	**113.6**	**8.2**	**1.3**	**1.7**
Top 10 Avg.	0.2	3.3	0.7	0.6	0.2	0.2	0.3	0.5	0.8	1.2	1.8	3.1	4.6	3.0	3.7	115.0	14.2	2.0	2.7
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.1	0.2	0.3	0.7	1.3	2.3	3.5	2.1	2.9	112.3	2.3	0.5	0.4
May Consensus	0.1	3.3	0.6	0.4	0.1	0.2	0.3	0.4	0.6	0.9	1.5	2.8	4.2	2.6	3.2	113.2	9.2	1.3	1.7
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	12	4	3	5	7	8	8	4	6	6	9	3	4	6	14	12	11
Same	38	29	15	14	27	21	21	30	29	29	16	11	5	9	15	7	10	15	17
Up	2	4	2	4	4	6	3	2	2	8	16	8	10	8	13	6	15	9	11
Diffusion Index	51%	56%	33%	50%	51%	52%	44%	43%	42%	55%	63%	54%	52%	63%	64%	50%	51%	46%	50%

First Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	0.3 H	na	0.4	na	na	na	na	0.3	0.6	1.0	1.8	na	na	na	na	na	6.0	1.7	1.4
Scotiabank Group	0.3 H	3.3 H	na	na	0.1	na	na	0.7	1.0	1.2	1.9	na	na	na	na	na	10.0	1.3	5.0 H
Via Nova Investment Mgt.	0.3 H	3.3 H	0.6	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	4.0	1.7	3.3	112.0	4.0	1.5	2.0
Daiwa Capital Markets America	0.2	3.3 H	0.5	0.2	0.2	0.3	0.3	0.5	0.7	1.0	1.6	2.8	4.2	na	3.4	114.0	12.0	1.5	2.0
Economist Intelligence Unit	0.2	3.3 H	na	0.2	0.2	0.2	0.2	0.3	0.4	0.8	1.4	na	na	na	3.4	na	1.0 L	na	1.8
Regions Financial Corporation	0.2	3.3 H	0.5	na	0.2	0.3	0.4	0.3	0.6	1.0	1.7	2.9	4.4	2.7	3.6	114.7	4.3	1.1	1.8
ACIMA Private Wealth	0.1	3.3 H	1.3 H	1.8 H	0.1	0.1	0.1	0.2	0.5	1.0	2.0	3.2	6.7 H	2.6	4.0	113.0	6.5	0.9	3.9
Action Economics	0.1	3.3 H	0.5	0.3	0.2	0.3	0.4	0.5	0.7	1.0	1.7	2.3	3.4	3.0	3.7	113.5	8.0	1.5	2.4
Amherst Pierpont Securities	0.1	3.3 H	0.6	0.4	0.3	0.4 H	0.8 H	1.1 H	1.5 H	1.8 H	2.6 H	3.7	5.0	3.5	4.3 H	115.0	4.2	2.4	2.9
Bank of America	0.1	na	0.4	na	na	na	na	0.8	0.9	1.3	1.9	na	na	na	na	na	11.0	1.2	1.2
Barclays	0.1	3.3 H	na	na	na	na	na	0.3	0.6	1.0	1.7	na	na	na	na	na	5.0	1.6	1.3
BMO Capital Markets	0.1	3.3 H	0.4	na	0.1	0.2	0.3	0.4	0.7	1.0	1.7	na	na	na	2.8	113.7	4.9	1.5	1.6
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.6	na	1.3	na	na	na	na	na	na	10.0	na	2.4
Chan Economics	0.1	3.3 H	0.6	0.4	0.1	0.2	0.2	0.2	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.9	5.0	2.0	2.1
Chmura Economics & Analytics	0.1	3.3 H	0.7	0.2	0.1	0.2	0.2	0.4	0.6	1.0	1.6	2.7	na	na	3.4	na	3.1	1.9	2.1
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	3.0	na	5.0	1.6	1.9
DePrince & Assoc.	0.1	3.3 H	0.4	0.4	0.1	0.1	0.1	0.2	0.4	0.8	1.5	3.1	4.0	2.6	3.0	111.3	4.8	1.7	1.8
Fannie Mae	0.1	3.3 H	na	na	0.2	0.2	0.2	0.2	0.5	0.8	1.5	na	na	na	3.0	na	8.7	1.2	2.8
Georgia State University	0.1	3.3 H	na	na	-0.1 L	-0.2 L	0.0 L	0.2	0.7	1.2	1.9	4.1 H	5.4	na	3.8	na	5.7	2.0	1.9
GLC Financial Economics	0.1	3.3 H	0.4	0.2	0.1	0.2	0.2	0.3	0.5	0.8	1.3	2.7	3.9	2.7	3.6	111.0	11.7	2.0	2.3
Goldman Sachs & Co.	0.1	na	na	na	0.4 H	na	na	na	na	0.8	na	na	na	na	2.9	na	8.0	1.4	2.2
Grant Thornton/Diane Swonk	0.1	3.3 H	0.3	0.3	0.2	0.2	0.3	0.1 L	0.2 L	0.5	1.3	1.9	3.9	na	2.9	na	14.0 H	0.4	1.8
Loomis, Sayles & Company	0.1	3.3 H	0.4	0.2	0.1	0.2	0.2	0.3	0.4	0.9	1.5	2.4	3.3	2.3	2.9	112.6	10.0	0.9	1.2
MacroFin Analytics & Rutgers Bus School	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	3.9	3.0	3.4	114.7	4.5	1.5	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.2	0.3	0.5	0.6	0.8	1.0	2.1	2.5	3.8	2.3	3.2	na	1.0 L	1.2	3.1
Moody's Capital Markets Group	0.1	3.3 H	0.5	0.3	0.1	0.1	0.2	0.2	0.4	0.8	1.4	2.6	4.1	2.7	3.2	115.7	6.4	1.5	1.9
MUFG Union Bank	0.1	3.3 H	0.2 L	na	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.5	4.0	2.7	3.1	116.0	5.0	1.5	2.3
Naroff Economic Advisors	0.1	3.3 H	1.2	1.6	0.2	0.2	0.3	0.4	0.7	1.0	1.6	2.5	4.1	2.7	3.7	113.0	3.5	1.4	1.4
NatWest Markets	0.1	3.2 L	0.4	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.9	3.1	107.0 L	4.7	2.4	3.0
Nomura Securities, Inc.	0.1	3.3 H	na	na	na	na	na	0.5	0.8	1.0	na	na	na	na	na	na	6.4	1.5	0.4 L
Oxford Economics	0.1	3.3 H	0.4	na	0.2	0.2	0.2	0.4	0.7	1.1	1.9	2.0	na	na	3.4	114.8	5.9	1.5	1.9
PNC Financial Services Corp.	0.1	3.3 H	0.2 L	na	0.1	0.2	0.2	0.2	0.5	0.8	1.6	na	4.2	1.0 L	3.1	na	7.6	-0.1 L	1.2
RDQ Economics	0.1	3.3 H	0.3	0.2	0.1	0.2	0.2	0.2	0.9	1.6	2.5	3.2	4.4	4.5 H	3.8	113.4	4.2	2.6	2.5
S&P Global	0.1	3.3 H	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	7.3	3.8 H	3.9
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.5	0.6	0.8	1.4	na	na	na	na	na	3.0	1.2	1.1
Swiss Re	0.1	3.3 H	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.3	4.7	na	2.7	na	5.1	na	2.9
The Northern Trust Company	0.1	3.3 H	0.5	0.2	0.2	0.2	0.3	0.5	0.7	0.9	1.5	2.5	3.4	3.2	2.9	111.0	7.0	1.4	1.3
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.3	0.3	0.3	0.3	0.4 L	1.1 L	1.8 L	2.6 L	1.0 L	2.4 L	118.0 H	4.0	0.8	0.5
Wells Fargo	0.1	3.3 H	0.3	0.1 L	0.2	0.2	0.3	0.5	0.8	1.3	2.0	2.5	3.9	2.4	3.4	na	2.0	2.0	2.3
ING	0.0 L	na	0.4	na	na	na	na	0.6	0.8	1.7	1.7	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.2**	**0.2**	**0.3**	**0.4**	**0.6**	**1.0**	**1.7**	**2.7**	**4.2**	**2.6**	**3.3**	**113.4**	**6.2**	**1.5**	**2.1**
Top 10 Avg.	0.2	3.3	0.7	0.6	0.2	0.3	0.4	0.6	0.9	1.4	2.1	3.2	4.8	3.1	3.8	115.1	10.3	2.3	3.2
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.3	2.3	3.6	2.1	2.9	111.8	3.0	0.9	1.1
May Consensus	0.1	3.3	0.6	0.4	0.2	0.2	0.3	0.4	0.7	1.0	1.6	2.8	4.3	2.6	3.2	112.9	6.6	1.7	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	1	1	13	6	2	3	8	9	8	7	4	6	6	3	2	4	7	12	12
Same	38	28	14	13	28	23	20	27	27	27	17	11	10	12	19	8	12	15	15
Up	2	4	2	3	4	6	3	2	3	6	16	8	8	5	11	7	20	9	12
Diffusion Index	51%	55%	31%	43%	53%	55%	42%	41%	43%	49%	66%	54%	54%	55%	64%	58%	67%	46%	50%

Second Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Amherst Pierpont Securities	0.6 H	3.7 H	1.0	0.8	0.6 H	0.8 H	1.3 H	1.5 H	1.9 H	2.3 H	3.1 H	4.1	5.4	3.8	4.5 H	115.5	3.9	2.3	2.8
Daiwa Capital Markets America	0.5	3.7 H	0.8	0.5	0.5	0.6	0.7	0.9	1.1	1.4	2.0	3.1	4.6	na	3.8	114.0	8.0	1.7	2.1
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.5	1.7	1.4
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.8	1.1	1.3	2.1	na	na	na	na	na	6.3	2.8	0.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	3.8	1.5	3.3	110.0	3.5	2.0	2.2
Action Economics	0.2	3.3	0.6	0.4	0.3	0.4	0.4	0.5	0.8	1.0	1.7	2.3	3.4	3.0	3.7	113.5	6.5	2.0	2.5
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.2	0.3	0.4	0.8	1.4	na	na	na	3.5	na	1.4 L	na	1.9
Regions Financial Corporation	0.2	3.3	0.5	na	0.3	0.3	0.4	0.3	0.6	1.1	1.8	2.9	4.5	2.8	3.7	115.2	4.0	1.3	1.9
ACIMA Private Wealth	0.1	3.3	1.3 H	1.7 H	0.1	0.1	0.1	0.2 L	0.5	1.3	2.3	3.5	7.0 H	2.5	3.8	110.0	2.5	0.9	2.7
Bank of America	0.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	6.0	1.4	1.6
Barclays	0.1	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	1.9	1.9
BMO Capital Markets	0.1	3.3	0.4	na	0.1	0.2	0.3	0.5	0.8	1.1	1.8	na	na	na	2.9	113.0	4.7	1.4	1.4
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.8	na	1.3	na	na	na	na	na	na	7.5	na	2.8
Chan Economics	0.1	3.3	0.6	0.5	0.1	0.2	0.2	0.2 L	0.3	0.6	1.3	2.6	4.6	2.6	3.3	113.7	1.6	2.0	2.0
Chmura Economics & Analytics	0.1	3.3	0.8	0.2	0.1	0.2	0.2	0.4	0.6	1.1	1.6	2.7	na	na	3.4	na	4.3	2.0	2.2
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.2	0.3	0.5	0.8	1.4	na	na	na	2.9	na	4.2	1.9	2.0
DePrince & Assoc.	0.1	3.3	0.5	0.3	0.1	0.1	0.2	0.3	0.4	0.9	1.5	3.1	4.0	2.7	3.0	110.9	3.8	1.8	1.9
Fannie Mae	0.1	3.3	na	na	0.2	0.2	0.2	0.3	0.5	0.8	1.5	na	na	na	2.9	na	5.2	1.1	2.4
Georgia State University	0.1	3.3	na	na	-0.1 L	-0.2 L	0.0 L	0.2 L	0.8	1.4	2.1	4.4 H	5.8	na	4.0	na	4.6	0.8	2.1
GLC Financial Economics	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5	0.8	1.2 L	2.5	3.8	2.5	3.6	110.8	9.7	1.9	2.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	na	na	1.0	na	na	na	na	2.9	na	6.5	1.2	1.7
Grant Thornton/Diane Swonk	0.1	3.3	0.3	0.3	0.1	0.2	0.3	0.2 L	0.1 L	0.4 L	1.2 L	1.8 L	2.8 L	na	2.7	na	10.1 H	0.9	2.0
Loomis, Sayles & Company	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	0.6	1.1	1.6	2.4	3.2	2.2	2.8	112.3	8.4	0.9	1.2
MacroFin Analytics & Rutgers Bus School	0.1	3.3	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.5	2.8	3.9	3.1	3.4	115.0	3.5	1.8	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.6	0.1 L	0.3	0.4	0.6	0.7	1.0	1.1	2.3	2.6	3.8	2.4	3.2	na	2.1	1.7	2.7
Moody's Capital Markets Group	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.2 L	0.4	0.9	1.5	2.6	4.0	2.6	3.1	116.3 H	4.5	1.7	0.9
MUFG Union Bank	0.1	3.3	0.2 L	na	0.1	0.1	0.2	0.2 L	0.4	0.7	1.4	2.5	4.0	2.6	3.1	116.0	2.5	1.5	2.6
Naroff Economic Advisors	0.1	3.3	1.2	1.7 H	0.2	0.3	0.5	0.6	0.8	1.2	1.8	2.8	4.2	2.9	3.9	112.0	2.3	1.7	1.7
NatWest Markets	0.1	3.2 L	0.3	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.9	3.9	2.7	2.9	106.0 L	3.7	2.3	2.0
Nomura Securities, Inc.	0.1	3.3	na	na	na	na	na	0.6	0.9	1.2	na	na	na	na	na	na	7.0	1.5	0.3 L
Oxford Economics	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.7	1.2	1.9	2.1	na	na	3.4	114.5	6.3	2.2	2.0
PNC Financial Services Corp.	0.1	3.3	0.2 L	na	0.1	0.2	0.2	0.2 L	0.5	0.9	1.7	na	4.3	1.1 L	3.0	na	6.0	0.6 L	1.4
RDQ Economics	0.1	3.3	0.3	0.2	0.1	0.2	0.2	0.2 L	1.2	2.1	3.0	3.7	4.8	5.1 H	4.2	113.4	4.2	2.7	2.6
S&P Global	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.9	1.3	2.1	na	na	na	3.6	na	4.3	5.6 H	4.5 H
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.6	0.7	0.8	1.4	na	na	na	na	na	2.5	1.2	1.5
Swiss Re	0.1	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7	na	2.0	na	1.0
The Northern Trust Company	0.1	3.3	0.5	0.2	0.2	0.3	0.3	0.5	0.8	1.1	1.7	2.7	3.6	3.4	3.1	110.8	5.6	1.6	1.5
TS Lombard	0.1	3.2 L	0.4	0.2	0.2	0.3	0.4	0.4	0.5	0.6	1.3	2.0	2.8 L	1.2	2.6 L	115.0	3.0	0.8	0.5
Wells Fargo	0.1	3.3	0.3	0.1 L	0.2	0.3	0.3	0.6	0.9	1.3	2.0	2.5	3.9	2.5	3.4	na	2.3	1.9	1.2
ING	0.0 L	na	0.4	na	na	na	na	0.6	0.9	1.7	1.7	na	na	na	na	na	na	na	na
June Consensus	**0.1**	**3.3**	**0.5**	**0.4**	**0.2**	**0.2**	**0.3**	**0.4**	**0.7**	**1.1**	**1.8**	**2.8**	**4.2**	**2.7**	**3.3**	**112.9**	**4.7**	**1.7**	**1.9**
Top 10 Avg.	0.3	3.4	0.8	0.7	0.3	0.4	0.5	0.8	1.1	1.5	2.3	3.4	5.0	3.2	3.9	114.9	7.6	2.6	2.8
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.3	3.5	2.1	2.8	110.9	2.2	1.0	1.0
May Consensus	0.2	3.3	0.6	0.5	0.2	0.3	0.4	0.5	0.7	1.1	1.7	2.9	4.2	2.6	3.3	112.5	4.8	1.9	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	2	1	9	6	4	6	8	10	11	7	5	6	6	5	3	3	11	13	16
Same	37	28	15	12	27	20	20	23	22	25	16	11	8	9	21	9	10	17	16
Up	2	4	3	4	3	6	3	2	2	5	13	8	10	6	8	7	18	6	7
Diffusion Index	50%	55%	39%	45%	49%	50%	42%	39%	37%	47%	62%	54%	58%	53%	58%	61%	59%	40%	38%

Third Quarter 2021

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Amherst Pierpont Securities	1.1 H	4.2 H	1.6 H	1.2	1.1 H	1.3 H	1.8 H	1.9 H	2.3 H	2.7 H	3.4 H	4.4	5.7	4.0	4.8 H	116.0	3.5	2.4	2.8
Daiwa Capital Markets America	0.8	3.9	1.1	0.8	0.7	0.8	0.9	1.3	1.5	1.7	2.4	3.5	4.8	na	4.0	114.0	4.5	1.9	2.2
Action Economics	0.4	3.5	0.7	0.5	0.4	0.4	0.4	0.5	0.8	1.0	1.7	2.3	3.4	3.0	3.8	113.4	na	na	na
Naroff Economic Advisors	0.4	3.5	1.5	1.9 H	0.4	0.6	0.8	0.9	1.1	1.4	2.1	3.1	4.4	3.1	4.1	111.0	2.1	1.7	1.8
TS Lombard	0.4	3.5	0.6	0.4	0.4	0.6	0.7	0.8	0.9	1.0	1.7	2.5	3.3	1.6	3.0	110.0	2.5	1.0	0.8 L
Chmura Economics & Analytics	0.3	3.4	0.8	0.3	0.3	0.3	0.4	0.5	0.8	1.2	1.7	2.8	na	na	3.4	na	3.0	1.7	1.7
J.P. Morgan Chase	0.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.2	1.5
Scotiabank Group	0.3	3.3	na	na	0.1	na	na	0.9	1.2	1.5	2.1	na	na	na	na	na	4.4	1.3	1.8
Via Nova Investment Mgt.	0.3	3.3	0.5	0.2	0.2	0.3	0.3	0.4	0.5	0.8	1.5	2.8	3.8	1.5	3.3	108.0	3.0	2.0	2.2
DePrince & Assoc.	0.2	3.4	0.6	0.5	0.2	0.2	0.3	0.4	0.6	1.0	1.6	3.2	4.1	2.7	3.1	110.5	3.4	1.8	1.9
Economist Intelligence Unit	0.2	3.3	na	0.3	0.2	0.2	0.3	0.3	0.5	1.0	1.5	na	na	na	3.5	na	2.1	na	2.2
Regions Financial Corporation	0.2	3.3	0.6	na	0.3	0.4	0.5	0.4	0.7	1.2	1.9	3.0	4.6	2.8	3.8	115.9	3.4	1.7	1.9
ACIMA Private Wealth	0.1	3.3	1.3	1.7	0.1	0.1	0.1 L	0.2 L	0.5	1.5	2.5	3.7	7.2 H	2.5	3.7	110.0	3.0	0.8	1.3
Bank of America	0.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.0	1.7	2.0
Barclays	0.1	3.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	4.0	2.3	2.5
BMO Capital Markets	0.1	3.3	0.4	na	0.1	0.2	0.3	0.5	0.9	1.2	1.9	na	na	na	3.0	112.2	4.1	1.4	1.5
BNP Paribas Americas	0.1	na	na	na	na	na	na	0.9	na	1.4	na	na	na	na	na	na	5.0	na	2.5
Chan Economics	0.1	3.3	0.7	0.5	0.2	0.3	0.3	0.3	0.4	0.7	1.4	2.7	4.7	2.7	3.4	113.9	1.5 L	2.0	2.1
Comerica Bank	0.1	3.2 L	0.4	na	0.1	0.2	0.3	0.3	0.5	0.8	1.4	na	na	na	2.8	na	3.7	2.0	2.0
Fannie Mae	0.1	3.3	na	na	0.2	0.2	0.2	0.3	0.5	0.8	1.5	na	na	na	2.9	na	3.5	0.9	1.7
Georgia State University	0.1	3.3	na	na	-0.1 L	-0.2 L	0.1 L	0.4	1.1	1.7	2.5	4.7 H	6.2	na	4.2	na	4.0	0.3 L	1.9
GLC Financial Economics	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.3	0.5	0.7	1.0 L	2.1	3.3	2.1	3.5	109.9	5.5	2.0	2.4
Goldman Sachs & Co.	0.1	na	na	na	0.3	na	na	na	na	1.1	na	na	na	na	3.0	na	5.0	1.3	1.7
Grant Thornton/Diane Swonk	0.1	3.3	0.3	0.3	0.1	0.2	0.4	0.2 L	0.1 L	0.3 L	1.2	1.7 L	3.2	na	2.5 L	na	6.7	0.6	1.2
Loomis, Sayles & Company	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	0.7	1.2	1.6	2.3	3.1 L	2.2	2.8	112.1	5.3	0.9	1.3
MacroFin Analytics & Rutgers Bus School	0.1	3.3	0.5	0.2	0.2	0.2	0.3	0.3	0.4	0.7	1.4	2.8	4.0	3.1	3.4	115.5	2.0	2.0	2.0
Mizuho Research Institute	0.1	na	na	na	na	na	na	na	na	0.8	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.1	3.2 L	0.7	0.1 L	0.4	0.5	0.7	0.9	1.1	1.3	2.4	2.7	3.7	2.4	3.3	na	7.6 H	1.5	3.1
Moody's Capital Markets Group	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.2 L	0.5	0.9	1.5	2.6	4.0	2.5	3.1	116.9	2.9	1.6	1.4
MUFG Union Bank	0.1	3.3	0.2 L	na	0.1	0.1	0.2	0.2 L	0.4	0.7	1.4	2.5	4.0	2.5	3.1	117.0 H	2.5	1.5	2.3
NatWest Markets	0.1	3.2 L	0.3	0.2	0.1	0.2	0.3	0.4	0.5	1.1	1.7	2.8	3.8	2.5	2.9	105.0 L	3.5	1.9	2.0
Nomura Securities, Inc.	0.1	3.3	na	na	na	na	na	0.7	1.1	1.4	na	na	na	na	na	na	5.9	1.5	0.9
Oxford Economics	0.1	3.3	0.4	na	0.2	0.2	0.3	0.4	0.8	1.2	2.0	2.1	na	na	3.5	113.9	7.2	2.1	2.0
PNC Financial Services Corp.	0.1	3.3	0.2 L	na	0.1	0.2	0.2	0.2 L	0.5	1.0	1.8	na	4.3	1.2 L	3.0	na	5.1	1.3	2.5
RDQ Economics	0.1	3.3	0.3	0.2	0.1	0.2	0.2	0.2 L	1.3	2.3	3.2	3.8	4.9	5.1 H	4.3	113.0	3.9	2.9	2.6
S&P Global	0.1	3.3	0.4	na	0.2	0.2	0.3	0.5	1.0	1.5	2.3	na	na	na	3.7	na	2.0	5.1 H	3.5 H
Societe Generale	0.1	na	na	na	0.1	0.1	na	0.7	0.8	1.0	1.7	na	na	na	na	na	2.5	1.2	1.5
Swiss Re	0.1	3.3	0.4	0.3	0.2	0.2	0.3	0.4	0.6	1.0	1.7	3.1	4.3	na	2.7	na	1.9	na	1.2
The Northern Trust Company	0.1	3.3	0.5	0.2	0.2	0.3	0.4	0.6	0.9	1.3	1.9	2.9	3.8	3.5	3.3	110.6	4.3	1.9	1.8
Wells Fargo	0.1	3.3	0.4	0.2	0.2	0.3	0.4	0.7	1.0	1.4	2.1	2.6	4.0	2.5	3.4	na	2.3	1.6	1.6
ING	0.0 L	na	0.4	na	na	na	na	0.9	1.2	1.9	1.9	na	na	na	na	na	na	na	na
June Consensus	**0.2**	**3.4**	**0.6**	**0.5**	**0.2**	**0.3**	**0.4**	**0.5**	**0.8**	**1.2**	**1.9**	**2.9**	**4.3**	**2.7**	**3.4**	**112.4**	**3.7**	**1.7**	**1.9**
Top 10 Avg.	0.5	3.5	1.0	0.8	0.5	0.6	0.7	1.0	1.3	1.8	2.5	3.5	5.1	3.3	4.0	115.0	5.8	2.5	2.6
Bottom 10 Avg.	0.1	3.3	0.3	0.2	0.1	0.1	0.2	0.2	0.4	0.7	1.4	2.3	3.5	2.1	2.9	109.9	2.1	1.0	1.3
May Consensus	0.2	3.4	0.7	0.6	0.3	0.3	0.4	0.6	0.8	1.2	1.8	3.0	4.3	2.6	3.3	112.2	3.6	1.8	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	6	3	8	5	7	9	10	10	13	8	6	7	6	6	5	4	6	13	15
Same	33	27	14	15	23	18	17	21	17	24	14	8	9	9	17	8	14	16	15
Up	2	3	5	2	4	5	4	4	5	5	14	10	9	5	10	7	18	6	8
Diffusion Index	45%	50%	44%	43%	46%	44%	40%	41%	39%	46%	62%	56%	56%	48%	58%	58%	66%	40%	41%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.13	0.13	0.13	0.75	0.90	1.00	--	--	--
BMO Capital Markets	0.13	0.13	0.13	0.75	0.85	1.10	115.1	114.5	113.0
IHSMarkit	--	--	--	0.66	0.66	0.67	--	--	--
ING Financial Markets	0.13	0.13	0.13	0.40	0.35	0.40	113.7	111.2	107.2
Mizuho Research Institute	--	--	--	0.70	0.75	0.80	--	--	--
Moody's Analytics	0.05	0.07	0.08	0.63	0.63	0.99	--	--	--
Moody's Capital Markets	0.13	0.13	0.13	0.72	0.75	0.85	114.8	115.1	116.0
Northern Trust	0.13	0.13	0.13	0.75	0.75	0.90	113.5	112.5	111.0
Oxford Economics	0.13	0.13	0.13	0.93	1.05	1.15	115.1	115.1	114.5
Scotiabank	0.13	0.13	0.13	0.85	1.05	1.30	--	--	--
TS Lombard	0.13	0.13	0.13	0.58	0.45	0.55	113.0	118.0	115.0
Wells Fargo	0.13	0.13	0.13	1.00	1.15	1.30	115.5	115.3	111.7
June Consensus	**0.12**	**0.12**	**0.13**	**0.73**	**0.78**	**0.92**	**114.4**	**114.5**	**112.6**
High	0.13	0.13	0.13	1.00	1.15	1.30	115.5	118.0	116.0
Low	0.05	0.07	0.08	0.40	0.35	0.40	113.0	111.2	107.2
Last Months Avg.	0.14	0.12	0.13	0.68	0.83	1.10	114.7	113.6	112.1

Japan

Blue Chip Forecasters	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.10	-0.10	-0.10	-0.05	0.00	0.00	107.0	104.0	105.0
BMO Capital Markets	-0.10	-0.10	-0.10	-0.05	-0.05	-0.10	108.0	110.0	112.0
IHSMarkit	--	--	--	--	--	--	107.8	109.9	112.1
ING Financial Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	106.0	105.0	105.0
Mizuho Research Institute	--	--	--	-0.05	0.00	0.00	107.0	108.0	109.0
Moody's Analytics	-0.10	-0.10	-0.10	-0.18	-0.47	-0.57	112.1	117.2	120.5
Moody's Capital Markets	-0.10	-0.10	-0.10	0.00	0.00	0.00	107.7	108.0	108.2
Nomura Securities	--	--	--	--	--	--	106.0	108.0	110.0
Northern Trust	-0.10	-0.10	-0.10	-0.05	-0.10	-0.05	109.0	108.0	108.0
Oxford Economics	-0.06	-0.06	-0.05	-0.11	-0.11	-0.09	106.3	106.0	106.0
Scotiabank	-0.10	-0.10	-0.10	--	--	--	107.0	107.0	106.0
TS Lombard	-0.06	-0.06	-0.06	0.00	0.00	0.00	107.7	108.0	110.0
Wells Fargo	-0.10	-0.10	-0.10	0.00	0.05	0.15	107.0	107.0	106.0
June Consensus	**-0.09**	**-0.09**	**-0.09**	**-0.05**	**-0.07**	**-0.07**	**107.6**	**108.2**	**109.1**
High	-0.06	-0.06	-0.05	0.00	0.05	0.15	112.1	117.2	120.5
Low	-0.10	-0.10	-0.10	-0.18	-0.47	-0.57	106.0	104.0	105.0
Last Months Avg.	-0.09	-0.09	-0.09	-0.11	-0.10	-0.07	108.6	108.6	109.4

United Kingdom

Blue Chip Forecasters	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.10	0.10	0.10	0.40	0.45	0.50	1.16	1.15	1.13
BMO Capital Markets	0.10	0.10	0.10	0.05	0.30	0.50	1.23	1.23	1.25
IHSMarkit	--	--	--	--	--	--	1.22	1.21	1.22
ING Financial Markets	0.10	0.10	0.10	0.75	1.00	1.25	1.21	1.22	1.31
Moody's Analytics	0.10	0.01	0.01	0.01	-0.14	0.09	1.26	1.30	1.40
Moody's Capital Markets	0.10	0.10	0.10	0.26	0.31	0.45	1.23	1.22	1.22
Nomura Securities	--	--	--	--	--	--	1.16	1.20	1.29
Northern Trust	0.10	0.10	0.10	0.30	0.35	0.40	1.23	1.24	1.28
Oxford Economics	0.10	0.10	0.10	0.40	0.48	0.67	1.25	1.26	1.28
Scotiabank	0.10	0.10	0.10	--	--	--	1.27	1.28	1.30
TS Lombard	0.10	0.10	0.10	0.19	0.25	0.30	1.24	1.18	1.15
Wells Fargo	0.10	0.10	0.10	0.40	0.55	0.75	1.20	1.21	1.24
June Consensus	**0.10**	**0.09**	**0.09**	**0.31**	**0.39**	**0.55**	**1.22**	**1.23**	**1.26**
High	0.10	0.10	0.10	0.75	1.00	1.25	1.27	1.30	1.40
Low	0.10	0.01	0.01	0.01	-0.14	0.09	1.16	1.15	1.13
Last Months Avg.	0.10	0.09	0.09	0.32	0.34	0.54	1.23	1.24	1.28

Switzerland

Blue Chip Forecasters	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.97	0.98	0.99
ING Financial Markets	-0.75	-0.75	-0.75	-0.40	-0.35	-0.30	0.95	0.94	0.94
Moody's Analytics	-0.75	-0.75	-0.75	-1.15	-1.06	-0.98	0.96	0.91	0.85
Moody's Capital Markets	-0.75	-0.75	-0.75	-0.50	-0.48	-0.45	0.97	0.98	0.98
Nomura Securities	--	--	--	--	--	--	0.96	0.95	0.95
Northern Trust	-0.75	-0.75	-0.75	-0.50	-0.45	-0.40	0.96	0.97	0.99
Oxford Economics	-0.75	-0.75	-0.75	-0.40	-0.36	-0.28	1.00	1.01	1.02
Scotiabank	--	--	--	--	--	--	0.95	0.94	0.93
TS Lombard	-0.75	-0.75	-0.75	-0.50	-0.50	-0.50	0.97	0.97	0.97
Wells Fargo	--	--	--	--	--	--	0.99	0.98	0.95
June Consensus	**-0.75**	**-0.75**	**-0.75**	**-0.58**	**-0.53**	**-0.49**	**0.97**	**0.96**	**0.96**
High	-0.75	-0.75	-0.75	-0.40	-0.35	-0.28	1.00	1.01	1.02
Low	-0.75	-0.75	-0.75	-1.15	-1.06	-0.98	0.95	0.91	0.85
Last Months Avg.	-0.75	-0.75	-0.75	-0.53	-0.51	-0.47	0.96	0.96	0.96

Canada

Blue Chip Forecasters	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
BMO Capital Markets	0.25	0.25	0.25	0.65	0.75	1.00	1.42	1.41	1.38
IHSMarkit	--	--	--	--	--	--	1.39	1.38	1.36
ING Financial Markets	0.25	0.25	0.25	0.75	0.75	1.00	1.40	1.35	1.27
Moody's Analytics	0.04	0.25	0.25	0.61	0.57	0.96	1.45	1.43	1.36
Moody's Capital Markets	0.25	0.25	0.25	0.58	0.60	0.62	1.39	1.40	1.41
Nomura Securities	--	--	--	--	--	--	1.45	1.40	1.37
Northern Trust	0.25	0.25	0.25	0.60	0.70	0.80	1.39	1.36	1.33
Oxford Economics	0.25	0.25	0.25	0.85	1.04	1.29	1.46	1.45	1.44
Scotiabank	0.25	0.25	0.25	0.90	1.00	1.30	1.39	1.38	1.35
TS Lombard	0.25	0.25	0.25	0.53	0.43	0.50	1.38	1.38	1.38
Wells Fargo	0.25	0.25	0.25	0.80	0.90	1.15	1.43	1.43	1.41
June Consensus	**0.23**	**0.25**	**0.25**	**0.70**	**0.75**	**0.96**	**1.41**	**1.40**	**1.37**
High	0.25	0.25	0.25	0.90	1.04	1.30	1.46	1.45	1.44
Low	0.04	0.25	0.25	0.53	0.43	0.50	1.38	1.35	1.27
Last Months Avg.	0.25	0.25	0.25	0.68	0.80	1.10	1.44	1.41	1.38

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
IHSMarkit	--	--	--	--	--	--	0.63	0.63	0.63
ING Financial Markets	0.25	0.25	0.50	--	--	--	0.63	0.66	0.71
Moody's Analytics	0.25	0.25	0.25	0.85	0.62	0.76	0.63	0.62	0.66
Moody's Capital Markets	0.25	0.25	0.25	0.93	0.97	1.05	0.66	0.65	0.65
Nomura Securities	--	--	--	--	--	--	0.62	0.61	0.63
Northern Trust	0.25	0.25	0.25	1.00	1.10	1.20	0.65	0.66	0.67
Oxford Economics	0.25	0.25	0.25	0.85	0.85	0.85	0.65	0.65	0.66
Scotiabank	0.25	0.25	0.25	--	--	--	0.62	0.63	0.66
TS Lombard	0.25	0.25	0.25	0.90	0.80	0.70	0.66	0.66	0.66
Wells Fargo	--	--	--	--	--	--	0.62	0.62	0.64
June Consensus	**0.25**	**0.25**	**0.29**	**0.91**	**0.87**	**0.91**	**0.64**	**0.64**	**0.66**
High	0.25	0.25	0.50	1.00	1.10	1.20	0.66	0.66	0.71
Low	0.25	0.25	0.25	0.85	0.62	0.70	0.62	0.61	0.63
Last Months Avg.	0.25	0.25	0.25	0.68	0.69	0.88	0.62	0.63	0.65

Euro area

Blue Chip Forecasters	Main Refinancing Rate			US$ per Euro		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.00	0.00	0.00	1.08	1.06	1.02
BMO Capital Markets	0.00	0.00	0.00	1.06	1.08	1.10
IHSMarkit	--	--	--	1.09	1.08	1.08
ING Financial Markets	0.00	0.00	0.00	1.10	1.12	1.15
Moody's Analytics	0.00	0.00	0.00	1.10	1.16	1.25
Moody's Capital Markets	0.00	0.00	0.00	1.08	1.08	1.07
Nomura Securities	--	--	--	1.07	1.09	1.12
Northern Trust	0.00	0.00	0.00	1.10	1.12	1.14
Oxford Economics	0.00	0.00	0.00	1.08	1.08	1.08
Scotiabank	0.00	0.00	0.00	1.10	1.12	1.14
TS Lombard	0.00	0.00	0.00	1.10	1.08	1.12
Wells Fargo	0.00	0.00	0.00	1.06	1.07	1.11
June Consensus	**0.00**	**0.00**	**0.00**	**1.09**	**1.10**	**1.12**
High	0.00	0.00	0.00	1.10	1.16	1.25
Low	0.00	0.00	0.00	1.06	1.06	1.02
Last Months Avg.	-0.05	-0.05	-0.05	1.09	1.10	1.12

Blue Chip Forecasters	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.60	-0.55	-0.50	--	--	--	--	--	--	--	--	--
BMO Capital Markets	-0.35	-0.20	-0.05	--	--	--	--	--	--	--	--	--
ING Financial Markets	--	--	--	-0.40	-0.35	-0.20	1.40	1.35	1.40	0.40	0.45	0.60
Moody's Analytics	-0.61	-0.56	-0.37	-0.13	-0.14	-0.06	2.31	1.93	1.76	0.84	0.99	0.66
Moody's Capital Markets	-0.40	-0.38	-0.30	0.04	0.05	0.18	1.59	1.60	1.65	0.72	0.73	0.85
Northern Trust	-0.50	-0.40	-0.30	0.00	0.05	0.10	1.70	1.60	1.50	0.70	0.60	0.50
Oxford Economics	-0.31	-0.24	-0.10	0.17	0.25	0.40	1.84	1.86	2.00	1.04	1.11	1.40
TS Lombard	-0.42	-0.50	-0.60	0.00	-0.08	-0.18	1.50	1.42	1.32	0.60	0.52	0.42
Wells Fargo	-0.40	-0.30	-0.10	--	--	--	--	--	--	--	--	--
June Consensus	**-0.45**	**-0.39**	**-0.29**	**-0.05**	**-0.04**	**0.04**	**1.72**	**1.63**	**1.61**	**0.72**	**0.73**	**0.74**
High	-0.31	-0.20	-0.05	0.17	0.25	0.40	2.31	1.93	2.00	1.04	1.11	1.40
Low	-0.61	-0.56	-0.60	-0.40	-0.35	-0.20	1.40	1.35	1.32	0.40	0.45	0.42
Last Months Avg.	-0.47	-0.41	-0.27	0.03	0.05	0.11	1.81	1.74	1.69	0.80	0.76	0.76

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.66	-0.78	-0.85	-0.98
United Kingdom	-0.45	-0.42	-0.38	-0.37
Switzerland	-1.17	-1.30	-1.31	-1.40
Canada	-0.15	-0.03	-0.03	0.04
Australia	0.21	0.18	0.09	-0.01
Germany	-1.15	-1.18	-1.17	-1.21
France	-0.70	-0.78	-0.82	-0.88
Italy	0.96	1.00	0.85	0.69
Spain	0.02	-0.01	-0.04	-0.18

Consensus Forecasts
Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.23	-0.21	-0.03	-0.22
United Kingdom	-0.03	-0.02	-0.03	-0.03
Switzerland	-0.88	-0.87	-0.87	-0.88
Canada	0.13	0.10	0.13	0.13
Australia	0.13	0.13	0.13	0.16
Euro area	-0.13	-0.12	-0.12	-0.13

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Special Questions

1. a. What do you think the peak monthly unemployment rate might be?

20.3%

b. What month would that happen?

May	Jun	Jul	Aug	Oct
61%	24%	6%	6%	3%

c. What do you think the U.S. unemployment rate will be:

at the end of 2020? 11.0%

at the end of 2021? 7.2%

2. The House of Representatives has voted for another $3 trillion in COVID-related federal aid for the economy. Senate passage of this exact bill is, however, open for negotiation.

a. How much more aid do you believe is needed for meaningful support of the economy?

$2.4 trillion

b. The federal government budget deficit was just under $1.0 trillion in fiscal 2019, which was 4.6% of GDP. How large do you see the budget deficit this year and next, and what percentage of GDP would that be?

FY 2020? $4.0 trillion % of GDP 18.9%

FY 2021? $2.5 trillion % of GDP 10.9%

3. The Federal Reserve continues to add substantial amounts to its balance sheet as it seeks to provide credit and/or to support lending by private institutions. By mid-May, its total assets were $6.9 trillion. How large do you estimate the Fed's balance sheet at

Year-end 2020? $9.4 trillion

Year-end 2021? $10.2 trillion

Assessing Credit Losses and Risks to the Banking System

With businesses shuttered and job losses mounting rapidly, there is growing concern over the ability of borrowers to service their debt obligations and the resulting risks to financial stability. We assess the likely scale of economy-wide credit losses, the exposure of creditors to those losses, and the potential risks to financial stability and the banking sector in this edition of the Analyst.

Assessing Credit Losses. We first look at corporate debt. Nonfinancial corporate debt grew by over 60% since 2011 and recently rose to an all-time high as a share of GDP, leading to growing concern even prior to the virus that corporate defaults could rise dramatically in the next downturn. The sharp decline in revenues across many industries has left a large share of companies with negative cash flow, and rising bankruptcy filings and cases suggest the corporate default cycle has started.

A unique feature of this downturn is the wide variation in industry exposure to the virus, with physical constraints on spending, occupational health risks, and geographical variation in the virus outbreak affecting industries differently. Assessing the likely scale of corporate credit losses thus requires a closer look at which industries are most affected and how large they are as share of total corporate debt, as virus-exposure will likely play a large role in determining credit losses alongside traditional cyclical factors.

To assess the impact of the virus across industries, we first look at changes in credit spreads from before the virus to the present for high-yield corporate bonds at the granular industry level. We categorize industries as directly impacted by the virus or only indirectly impacted by the virus, based on a breakdown by our credit strategists and our assessment of which industries have been hardest hit by the virus thus far. Looking across roughly 80 industries, we find that the energy sector and industries directly impacted by the virus have seen significantly larger increases in credit spreads. While translating these numbers to default risk remains challenging given changes in risk premiums, they suggest that default rates will largely be driven by industry exposure to the virus.

The energy sector stands out both in terms of its size and default risks, given the collapse in oil demand, its disproportionately large footprint in the corporate bond market relative to its GDP share, and the heavy amounts of leverage in the sector. We estimate that roughly half of high-yield corporate bonds are in the energy or virus-impacted industries. Overall, our credit strategists estimate that the 12-month trailing high-yield default rate will increase to 13% by the end of 2020, similar to the peak rate reached during the Global Financial Crisis.

Another key area of concern is commercial real estate (CRE), given signs of overheating and overstretched valuations prior to the virus, as well as the unprecedented declines in demand in industries such as lodging, healthcare, and retail. Commercial real estate prices have outpaced single family house prices since the prior downturn, with CRE capitalization rates falling to historically low levels. Late payments on commercial mortgages have picked up sharply in recent months, suggesting mounting pressures.

Once again, the unique nature of this downturn suggests that variation in virus exposure will play a large role in determining the breadth and depth of credit losses in commercial real estate. Delinquencies by property type already show wide dispersion, with virus-exposed property types such as lodging and retail showing much higher delinquency rates

than less exposed property types such as self-storage. This contrasts with the prior real estate bust, when delinquencies were roughly evenly distributed across property types. Overall, our housing strategists expect a deeper contraction of property incomes than during the financial crisis period, given the heavy stresses to rents and occupancy rates facing many properties, and overall losses on commercial mortgages similar to those observed during the financial crisis.

In contrast to corporate debt, consumer debt should see lower default and delinquency rates thanks to strong household balance sheets, expanded unemployment benefits and stimulus payments, and public and private forbearance provisions. Early signs suggest the policy response is helping most consumers stay current on their bills. For these reasons, our housing strategists also expect significantly smaller losses on residential loans than during the prior downturn. Nevertheless, significant downside risks to household debt remain, particularly if unemployment insurance benefits are not extended, and if higher out-of-pocket medical expenses due to loss of employer-based health insurance push more households to default.

Who Bears the Losses? We next look to see where credit losses are most likely to be felt. The Fed's Financial Accounts suggests that the banking system plays a large role in providing credit for commercial real estate and overall corporate borrowing, two areas of greater concern. Household debt is also largely held by banks, particularly residential mortgages, credit card loans, and auto loans, while student debt is largely held by the federal government.

Municipal debt, another area of concern, is largely held by households, mutual funds and pensions funds, and insurance companies, and thus likely poses a smaller threat to financial stability. Lastly, a growing share of corporate lending—especially in riskier categories, such as leveraged loans—is now done by nonbank financial institutions, including collateralized loan obligations (CLOs), asset managers, hedge funds, and private equity companies, and such lending is not well captured in the Fed's Financial Accounts. TIC data provides some evidence that non-bank financial institutions and insurance companies own much of US CLO securities, a growing area of concern. Crucially, CLOs do not generally permit early redemptions and are thus less susceptible to runs, and our credit strategists do not see CLOs posing a major risk to financial stability, despite the likely significant pickup in defaults on leveraged loans.

Banks are highly exposed to many areas of credit, while households, mutual funds, and pensions are largely more exposed to equities. Insurance companies are somewhere in between, and hold a significant amount of exposure to corporate debt, including CLOs.

Given the large size of the banking system, its importance in credit provision, and its outsized role in amplifying the economic shocks of the last downturn, we next turn to assessing the risks of the credit downturn to the banking system.

Risks to the Banking System. The Fed's Financial Stability Report warned that financial sector vulnerabilities, including for the banking sector, are likely to be significant in the near term, while the April FOMC minutes indicated concern that banks could come under greater stress, particularly if more adverse economic scenarios were realized. The Fed's Senior Loan Officer Opinion Survey (SLOOS) indicated that lending standards tightened significantly, particularly for commercial and industrial (C&I) and CRE loans, with most banks citing a less favorable or more uncertain economic outlook, as well as a reduced tolerance for risk, as reasons for tightening lending standards. Loan loss provisions across banks have increased significantly in preparation for the rise in defaults and delinquencies.

While further losses are likely to come, there are several reasons why banks may prove more resilient than during the financial crisis. The banking system is much better capitalized, with capital ratios comfortably above their required minimum levels. Only a modest percentage of banks cited a deterioration in their capital position as playing a role in tightening lending standards in the first quarter. In addition, residential real estate remains the largest category of lending in the banking system by a significant margin. Given that this downturn was not precipitated by a housing crisis, losses on this particularly large category will likely be smaller than during the GFC.

One potential worry is that certain industries are heavily exposed to the virus, which may lead to larger risks to the banking system if the lending of particular banks, or the banking system as a whole, is highly concentrated in these industries. Disclosures on industry exposure provided by relatively large banks suggest that the exposure of the banking system to at-risk industries appears manageable. Moreover, most individual large banks are not heavily concentrated in at-risk industries, although smaller banks may be more geographically constrained and thus concentrated in particular industries.

We next assess the vulnerability of bank balance sheets as of 2019Q4, using comprehensive balance sheet data across all FDIC-insured institutions. We estimate the losses on total bank equity from losses across asset categories, based on projections from our bank and credit analysts and our economic projections. We assume similar losses on C&I and CRE lending as in the 2008 crisis, but a smaller hit on residential mortgages and consumer loans. Crucially, we do not build in large effects from the fiscal stimulus package, which should ease the burden of losses for the private sector, especially for household and small business loans.

We calculate the estimated losses as a percent of total bank equity capital, using our outlined assumptions. We estimate that losses on C&I, CRE, consumer, and residential real estate loans would amount to roughly 15% of total bank equity, compared to around 30% of total bank equity at risk heading into the Global Financial Crisis, using ex-post realized losses across the same categories. Two main reasons account for this difference: first, losses on the large residential real estate category are likely to be smaller, and second, bank equity levels are higher today than before the crisis.

We next look at lending exposure of the largest banks individually, using bank-specific details from regulatory data covering all large banks operating in the US. Bank-level data can reveal differences across banks and highlight whether there are a significant number of banks with large exposures to at-risk categories. We again compare the largest banks' exposure across major loan categories today to their exposure across these categories in 2007. Where available, we use bank-level disclosures on exposures to high-risk industries, applying a higher loss rate for banks with higher exposures.

We find that while there is dispersion among the largest banks in their exposure to losses, almost all of the largest banks today are less vulnerable than the median large bank was prior to the financial crisis. Again, our finding is driven by both the smaller losses in the large real estate category and by banks' higher equity capital levels today.

While financial stability concerns appear manageable, significant downside risks remain. A slower than expected recovery and a prolonged downturn would likely stress the banking system further, and a growing share of riskier lending is now done by less regulated nonbank financial institutions, where risks are harder to assess. Should a more adverse scenario arise, Fed officials have indicated the willingness to further help facilitate the provision of credit by the financial system.

David Choi (Goldman Sachs)

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2021 through 2026 and averages for the five-year periods 2022-2026 and 2027-2031. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2021	2022	2023	2024	2025	2026	2022-2026	2027-2031
1. Federal Funds Rate	**CONSENSUS**	**0.2**	**0.4**	**1.0**	**1.6**	**1.9**	**2.1**	**1.4**	**2.3**
	Top 10 Average	0.4	0.8	1.6	2.2	2.5	2.7	1.9	2.8
	Bottom 10 Average	0.1	0.1	0.4	1.0	1.3	1.5	0.9	1.7
2. Prime Rate	**CONSENSUS**	**3.4**	**3.6**	**4.1**	**4.7**	**5.0**	**5.2**	**4.5**	**5.4**
	Top 10 Average	3.5	3.9	4.6	5.3	5.5	5.7	5.0	5.9
	Bottom 10 Average	3.3	3.3	3.7	4.2	4.5	4.7	4.1	4.9
3. LIBOR, 3-Mo.	**CONSENSUS**	**0.6**	**0.9**	**1.4**	**2.0**	**2.3**	**2.4**	**1.8**	**2.6**
	Top 10 Average	0.8	1.3	1.9	2.5	2.7	3.0	2.3	3.1
	Bottom 10 Average	0.4	0.5	0.9	1.6	1.9	2.0	1.4	2.1
4. Commercial Paper, 1-Mo	**CONSENSUS**	**0.6**	**0.9**	**1.4**	**2.0**	**2.2**	**2.3**	**1.7**	**2.6**
	Top 10 Average	0.7	1.2	1.8	2.3	2.6	2.8	2.1	3.0
	Bottom 10 Average	0.3	0.5	1.1	1.6	1.9	2.0	1.4	2.2
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**0.2**	**0.5**	**1.1**	**1.6**	**1.9**	**2.1**	**1.4**	**2.3**
	Top 10 Average	0.4	0.9	1.6	2.2	2.4	2.6	1.9	2.8
	Bottom 10 Average	0.1	0.2	0.5	1.1	1.4	1.6	0.9	1.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**0.3**	**0.6**	**1.1**	**1.7**	**2.0**	**2.2**	**1.5**	**2.5**
	Top 10 Average	0.4	0.9	1.7	2.3	2.6	2.7	2.0	3.0
	Bottom 10 Average	0.2	0.2	0.6	1.2	1.5	1.7	1.1	1.9
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**0.4**	**0.7**	**1.3**	**1.8**	**2.1**	**2.3**	**1.7**	**2.6**
	Top 10 Average	0.5	1.1	1.8	2.4	2.7	2.9	2.2	3.1
	Bottom 10 Average	0.2	0.3	0.7	1.3	1.6	1.8	1.1	2.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**0.5**	**0.9**	**1.5**	**2.0**	**2.3**	**2.5**	**1.8**	**2.7**
	Top 10 Average	0.8	1.3	2.0	2.5	2.9	3.0	2.4	3.3
	Bottom 10 Average	0.3	0.4	0.9	1.4	1.7	2.0	1.3	2.2
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**0.7**	**1.1**	**1.7**	**2.2**	**2.5**	**2.7**	**2.0**	**2.9**
	Top 10 Average	1.1	1.6	2.3	2.8	3.1	3.3	2.6	3.5
	Bottom 10 Average	0.5	0.7	1.2	1.6	1.8	2.1	1.5	2.3
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**1.2**	**1.5**	**2.1**	**2.5**	**2.7**	**2.9**	**2.3**	**3.1**
	Top 10 Average	1.5	2.0	2.6	3.1	3.3	3.5	2.9	3.8
	Bottom 10 Average	0.8	1.1	1.6	1.9	2.1	2.2	1.8	2.5
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**1.8**	**2.2**	**2.7**	**3.1**	**3.3**	**3.5**	**3.0**	**3.8**
	Top 10 Average	2.2	2.7	3.3	3.7	3.9	4.1	3.5	4.4
	Bottom 10 Average	1.4	1.7	2.2	2.6	2.8	2.9	2.4	3.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**2.8**	**3.2**	**3.6**	**4.0**	**4.2**	**4.3**	**3.9**	**4.6**
	Top 10 Average	3.1	3.6	4.2	4.6	4.7	4.8	4.4	5.1
	Bottom 10 Average	2.4	2.7	3.1	3.5	3.7	3.8	3.4	4.2
13. Corporate Baa Bond Yield	**CONSENSUS**	**4.1**	**4.5**	**4.9**	**5.2**	**5.3**	**5.4**	**5.0**	**5.7**
	Top 10 Average	4.6	5.0	5.4	5.7	5.8	6.0	5.6	6.2
	Bottom 10 Average	3.6	3.9	4.3	4.6	4.7	4.8	4.4	5.2
14. State & Local Bonds Yield	**CONSENSUS**	**2.6**	**3.0**	**3.5**	**3.7**	**3.8**	**3.8**	**3.6**	**4.1**
	Top 10 Average	3.0	3.3	3.9	4.2	4.3	4.4	4.0	4.6
	Bottom 10 Average	2.3	2.6	2.9	3.2	3.2	3.3	3.0	3.7
15. Home Mortgage Rate	**CONSENSUS**	**3.4**	**3.6**	**4.0**	**4.4**	**4.5**	**4.7**	**4.2**	**4.9**
	Top 10 Average	3.8	4.0	4.5	4.8	5.0	5.2	4.7	5.5
	Bottom 10 Average	3.0	3.2	3.5	3.9	4.1	4.1	3.7	4.4
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**112.8**	**112.6**	**112.5**	**111.8**	**111.4**	**111.0**	**111.9**	**110.6**
	Top 10 Average	114.1	114.5	114.1	113.8	113.5	113.4	113.9	113.9
	Bottom 10 Average	111.7	110.7	110.7	110.2	109.5	108.7	110.0	107.6
		Year-Over-Year, % Change						Five-Year Averages	
		2021	2022	2023	2024	2025	2026	2022-2026	2027-2031
B. Real GDP	**CONSENSUS**	**3.2**	**3.2**	**2.4**	**2.2**	**2.1**	**2.0**	**2.4**	**2.1**
	Top 10 Average	5.7	4.3	2.9	2.5	2.3	2.3	2.9	2.4
	Bottom 10 Average	0.5	2.2	1.9	1.9	1.8	1.8	1.9	1.8
C. GDP Chained Price Index	**CONSENSUS**	**1.1**	**1.7**	**1.9**	**2.0**	**2.0**	**2.0**	**1.9**	**2.0**
	Top 10 Average	1.8	2.2	2.2	2.2	2.3	2.2	2.2	2.2
	Bottom 10 Average	0.3	1.3	1.6	1.8	1.8	1.8	1.7	1.9
D. Consumer Price Index	**CONSENSUS**	**1.3**	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.2**
	Top 10 Average	2.2	2.5	2.3	2.3	2.4	2.3	2.4	2.4
	Bottom 10 Average	0.4	1.5	1.8	1.8	1.9	1.9	1.8	2.0

Databank:

2020 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	-0.4	-8.3	-16.4	....	....	....	....	....	....	....	....
Auto & Light Truck Sales (b)	16.93	16.75	11.36	8.58	....	....	....	....	....	....	....	....
Personal Income (a, current $)	0.5	0.6	-2.0	....	....	....	....	....	....	....	....	....
Personal Consumption (a, current $)	0.4	0.2	-7.5	....	....	....	....	....	....	....	....	....
Consumer Credit (e)	3.0	5.7	-3.4	....	....	....	....	....	....	....	....	....
Consumer Sentiment (U. of Mich.)	99.8	101.0	89.1	71.8	73.7	....	....	....	....	....	....	....
Household Employment (c)	-89	45	-2987	-22369	....	....	....	....	....	....	....	....
Nonfarm Payroll Employment (c)	214	251	-881	-20537	....	....	....	....	....	....	....	....
Unemployment Rate (%)	3.6	3.5	4.4	14.7	....	....	....	....	....	....	....	....
Average Hourly Earnings (All, cur. $)	28.43	28.52	28.67	30.01	....	....	....	....	....	....	....	....
Average Workweek (All, hrs.)	34.3	34.4	34.1	34.2	....	....	....	....	....	....	....	....
Industrial Production (d)	-0.9	-0.3	-4.9	-15.0	....	....	....	....	....	....	....	....
Capacity Utilization (%)	76.7	76.7	73.2	64.9	....	....	....	....	....	....	....	....
ISM Manufacturing Index (g)	50.9	50.1	49.1	41.5	....	....	....	....	....	....	....	....
ISM Nonmanufacturing Index (g)	55.5	57.3	52.5	41.8	....	....	....	....	....	....	....	....
Housing Starts (b)	1.617	1.567	1.276	0.891	....	....	....	....	....	....	....	....
Housing Permits (b)	1.536	1.438	1.356	1.066	....	....	....	....	....	....	....	....
New Home Sales (1-family) (h)	774	717	619	623	....	....	....	....	....	....	....	....
Construction Expenditures (a)	2.6	-2.5	0.9	....	....	....	....	....	....	....	....	....
Consumer Price Index (nsa, d)	2.5	2.3	1.5	0.3	....	....	....	....	....	....	....	....
CPI ex. Food and Energy (nsa, d)	2.3	2.4	2.1	1.4	....	....	....	....	....	....	....	....
Producer Price Index (nsa, d)	2.1	1.3	0.7	-1.2	....	....	....	....	....	....	....	....
Durable Goods Orders (a)	-0.2	2.0	-16.6	-17.2	....	....	....	....	....	....	....	....
Leading Economic Indicators (a)	0.4	-0.2	-7.4	-4.4	....	....	....	....	....	....	....	....
Balance of Trade & Services (f)	-45.5	-39.8	-44.4	....	....	....	....	....	....	....	....	....
Federal Funds Rate (%)	1.55	1.58	0.65	0.05	....	....	....	....	....	....	....	....
3-Mo. Treasury Bill Rate (%)	1.55	1.54	0.30	0.14	....	....	....	....	....	....	....	....
10-Year Treasury Note Yield (%)	1.76	1.50	0.87	0.66	....	....	....	....	....	....	....	....

2019 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.5	-0.1	1.6	0.5	0.4	0.4	0.6	0.4	-0.4	0.5	0.0	0.1
Auto & Light Truck Sales (b)	16.71	16.52	17.26	16.48	17.39	17.18	16.88	16.97	17.15	16.52	16.99	16.65
Personal Income (a, current $)	0.3	0.6	0.4	0.3	0.2	0.4	0.0	0.4	0.2	0.1	0.5	0.2
Personal Consumption (a, current $)	0.6	-0.1	1.0	0.7	0.4	0.3	0.5	0.3	0.2	0.3	0.3	0.4
Consumer Credit (e)	5.2	4.8	3.6	5.1	4.3	3.5	6.7	4.5	3.1	3.9	2.1	6.1
Consumer Sentiment (U. of Mich.)	91.2	93.8	98.4	97.2	100.0	98.2	98.4	89.8	93.2	95.5	96.8	99.3
Household Employment (h)	-198	239	-125	-45	148	304	198	549	403	246	-8	267
Nonfarm Payroll Employment (c)	269	1	147	210	85	182	194	207	208	185	261	184
Unemployment Rate (%)	4.0	3.8	3.8	3.6	3.6	3.7	3.7	3.7	3.5	3.6	3.5	3.5
Average Hourly Earnings (All, cur. $)	27.58	27.69	27.76	27.81	27.87	27.96	28.05	28.16	28.16	28.24	28.34	28.37
Average Workweek (All, hrs.)	34.5	34.4	34.5	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.3	34.3
Industrial Production (d)	3.6	2.7	2.3	0.7	1.7	1.0	0.4	0.3	-0.2	-0.8	-0.4	-0.8
Capacity Utilization (%)	79.0	78.5	78.4	77.8	77.8	77.7	77.4	77.8	77.4	77.0	77.6	77.2
ISM Manufacturing Index (g)	55.5	54.1	54.6	53.4	52.3	51.6	51.3	48.8	48.2	48.5	48.1	47.8
ISM Nonmanufacturing Index (g)	56.0	58.5	56.3	55.7	56.3	55.4	54.8	56.0	53.5	54.4	53.9	54.9
Housing Starts (b)	1.272	1.137	1.203	1.267	1.268	1.235	1.212	1.377	1.274	1.340	1.371	1.587
Housing Permits (b)	1.316	1.305	1.327	1.330	1.338	1.273	1.366	1.471	1.437	1.503	1.510	1.457
New Home Sales (1-family) (h)	637	665	700	664	600	726	661	706	726	706	696	731
Construction Expenditures (a)	1.4	0.5	0.8	0.6	-0.7	-0.9	0.5	1.1	0.7	0.4	1.6	0.4
Consumer Price Index (nsa, d)	1.6	1.5	1.9	2.0	1.8	1.6	1.8	1.7	1.7	1.8	2.1	2.3
CPI ex. Food and Energy (nsa, d)	2.2	2.1	2.0	2.1	2.0	2.1	2.2	2.4	2.4	2.3	2.3	2.3
Producer Price Index (nsa, d)	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.4
Durable Goods Orders (a)	0.2	-3.3	4.0	-4.7	-1.5	0.1	2.5	0.5	-0.9	-0.1	-2.6	2.8
Leading Economic Indicators (a)	0.0	0.2	0.2	0.1	0.0	0.0	0.4	-0.2	-0.2	-0.2	0.2	-0.2
Balance of Trade & Services (f)	-53.8	-51.3	-52.7	-51.3	-54.8	-54.3	-53.2	-53.9	-51.3	-47.4	-43.8	-48.6
Federal Funds Rate (%)	2.40	2.40	2.41	2.42	2.39	2.38	2.40	2.13	2.04	1.83	1.55	1.55
3-Mo. Treasury Bill Rate (%)	2.42	2.44	2.45	2.43	2.40	2.22	2.15	1.99	1.93	1.68	1.57	1.57
10-Year Treasury Note Yield (%)	2.71	2.68	2.57	2.53	2.40	2.07	2.06	1.63	1.70	1.71	1.81	1.86

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level; (h) thousands. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
June 1 ISM Manufacturing (May) IHS Markit Mfg PMI (May) Construction (Apr) NABE Outlook (Q2)	**2**	**3** ADP Employment Report(May) MSIO (Apr) ISM Nonmanufacturing (May) IHS Markit Services PMI(May) EIA Crude Oil Stocks Mortgage Applications	**4** Productivity & Costs (Q1) International Trade (Apr) Public Debt (May) Challenger Employment Report (May) Weekly Jobless Claims Weekly Money Supply	**5** Employment Situation (May) Consumer Credit (Apr)
8 QFR (Q1) Treasury Auction Allotments (May**)**	**9** JOLTS (Apr) Wholesale Trade (Apr) Manpower Survey (Q3) NFIB (May) Kansas City Financial Stress Index (May) FOMC Meeting	**10** CPI (May) Monthly Treasury (May) Kansas City Fed Labor Market Conditions Indicators (May) FOMC Meeting EIA Crude Oil Stocks Mortgage Applications	**11** PPI (May) QSS (Q1) Weekly Jobless Claims Weekly Money Supply	**12** Import & Export Prices (May) Consumer Sentiment (Jun, Preliminary) Livingston Survey (Jun)
15 Empire State Mfg Survey (Jun) TIC Data (Apr)	**16** Advance Retail Sales (May) IP (May) MTIS (Apr)	**17** New Residential Construction (May) EIA Crude Oil Stocks Mortgage Applications	**18** ECEC (Q1) Philadelphia Fed Mfg Business Outlook Survey (Jun) Composite Indexes (May Weekly Jobless Claims Weekly Money Supply)	**19** Regional Retail Sales (May) International Transactions(Q1)
22 Existing Home Sales (May) Treasury Auction Allotments (Jun) Chicago Fed National Activity Index (May)	23 New Residential Sales (May) Final Building Permits (May) Philadelphia Fed Nonmfg Bus Outlook Survey (Jun) Richmond Fed Mfg & Service Sector Surveys (Jun) Steel Imports (May, Prelim) IHS Markit Flash US Composite PMI (Jun)	**24** FHFA HPI (Apr) EIA Crude Oil Stocks Mortgage Applications	**25** Adv Trade & Inventories(May) GDP (Q1, 3rd Estimate) Advance Durable Goods (May) Kansas City Fed Manufacturing Survey (Jun) Weekly Jobless Claims Weekly Money Supply)	**26** Personal Income (May) Dallas Fed Trimmed-Mean PCE (May) Underlying NIPA Tables (May) Consumer Sentiment (Jun, Final) FRB Philadelphia Coincident Economic Activity Index (May)
29 Texas Manufacturing Outlook Survey (Jun) Pending Home Sales (May)	30 IIP (Q1) Case-Shiller HPI (Apr) Consumer Confidence (Jun Agricultural Prices (May) Chicago PMI (Jun) Texas Service Sector Outlook Survey (Jun)	**July 1** ADP Employment Report (Jun) Construction (May) ISM Manufacturing (Jun) IHS Markit Mfg PMI (Jun) Challenger Employment Report (Jun) EIA Crude Oil Stocks Mortgage Applications	**2** Employment Situation (Jun) Intl Trade/Supplement (May) Manufacturers' Shipments, Inventories & Orders (May) Weekly Jobless Claims Weekly Money Supply)	3
6 GDP by Industry (Q1) ISM Nonmanufacturing (Jun) IHS Markit Services PMI(Jun)	**7** JOLTS (May) Public Debt (Jun)	**8** Consumer Credit (May) Kansas City Fed Labor Market Conditions Indicators (Jun) EIA Crude Oil Stocks Mortgage Applications	**9** Wholesale Trade (May) Transportation Services Index (May) Kansas City Financial Stress Index (Jun) Weekly Jobless Claims Weekly Money Supply)	**10** Producer Prices (Jun)

BLUE CHIP FORECASTERS

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PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-57. Provide a copy of the Duke Energy Business Service Cost Allocation Manual. To the extent any costs are allocated to Piedmont using methods other than those specified in the DEBS cost allocation manual, identify such methods and the amount of allocated costs incurred in 2019 by allocation method.

RESPONSE: See attachment 1 for a summary of all allocated costs exclusive of service company allocations for 2019. Costs allocated to both capital and O&M have been included on a Piedmont total basis as well as a Tennessee allocated basis.

See attachments 2 thru 5 for the DEBS Cost Allocation Manual and matrix for 2019 and 2020. Attachments 3 and 5 provide the percentages applicable to Piedmont for each cost allocation pool.

See attachments 6 and 7 for a description of the Natural Gas Business Unit overhead allocations.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Kendrick C. Fentress
Associate General Counsel

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Apr 01 2019

April 1, 2019

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Cost Allocation Manual
Docket Nos. E-7, Sub 1100A; E-2, Sub 1095A; and G-9, Sub 682A

Dear Ms. Jarvis:

Pursuant to Regulatory Condition No. 5.5(c) set forth in the Commission's *Order Granting Motion to Amend Regulatory Conditions* issued on August 24, 2018, enclosed for filing is the 2019 Cost Allocation Manual ("CAM") of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc. in the referenced dockets.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

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Apr 01 2019

CERTIFICATE OF SERVICE

I certify that a copy of the 2019 Cost Allocation Manual of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc., in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A and G-9, Sub 682A, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 1st day of April, 2019.

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Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont)

Cost Allocation Manual - 2019

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A. INTRODUCTION

This Carolinas' Cost Allocation Manual ("CAM") documents the guidelines and procedures for allocating costs between the different business units impacting DEC, DEP, and Piedmont. The guidelines are intended to provide the foundation for proper identification and recording of transactions involving the exchange of services or goods between DEC, DEP, Piedmont and their Affiliates. These guidelines describe the allocation methods that are consistent with cost causation principles to ensure one Duke Energy entity does not subsidize another. Additional information on Duke Energy's internal controls and finance policies is available for Duke Energy employees on the employee portal.

Per the Regulatory Conditions in the *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct* issued September 29, 2016 by the North Carolina Utilities Commission ("Commission") in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, as amended by the *Order Granting Motion to Amend Regulatory Conditions* issued by the Commission in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A, the following merger conditions apply to the CAM:

5.5 Charges for and Allocations of the Costs of Affiliate Transactions.

To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC, DEP, and Piedmont shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DEC, DEP, or Piedmont, any Utility Affiliate, DEBS, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to DEC, DEP, or Piedmont. Piedmont will adopt DEC's and DEP's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DEC, DEP, Piedmont, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

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(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DEC, DEP, and Piedmont shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC, DEP, or Piedmont has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice Is Required.

With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC, DEP, or Piedmont may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

In addition to the CAM as a cost charging guide, DEC, DEP, and Piedmont use OpenPages to track compliance with regulatory requirements. OpenPages is administered by Corporate Compliance, which serves DEC, DEP, and Piedmont. OpenPages allows a regulatory requirement to be broken down into actionable tasks and assigned to one or more individuals. Individuals must complete tasks assigned and report completion by a certain date. OpenPages is integral to DEC's, DEP's, and Piedmont's culture of compliance.

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B. SUMMARY OF CORPORATE STRUCTURE [1]

AS OF DECEMBER 31, 2018

- Duke Energy Corporation
  - Bison Insurance Company Limited
    - NorthSouth Insurance Company Limited
  - Cinergy Corp.
    - Cinergy Global Resources, Inc.
    - Duke Energy Renewables Holding Company, LLC
      - Duke Energy Commercial Enterprises, Inc.
      - Duke Energy Renewables, Inc.
    - Cinergy Receivables Company, LLC
    - Duke Energy Indiana, LLC
    - Duke Energy Ohio, Inc.
      - Duke Energy Beckjord, LLC
      - Duke Energy Kentucky, Inc.
      - KO Transmission Company
      - Miami Power Corporation
      - Ohio Valley Electric Corporation
      - Tri-State Improvement Company
    - Duke Energy SAM, LLC
    - Duke Energy Transmission Holding Company, LLC
    - Duke Technologies, Inc.
      - Duke Energy One, Inc.
    - Progress Fuels, LLC
  - Duke Energy Clean Energy Resources, LLC
  - Duke Energy Renewables NC Solar, LLC
  - Duke Energy Pipeline Holding Company, LLC
    - Duke Energy ACP, LLC
    - Duke Energy Sabal Trail, LLC
    - Piedmont ENCNG Company, LLC
    - Piedmont Constitution Pipeline Company, LLC
    - DEPHCO Logistics, LLC
  - Duke Energy Carolinas, LLC
  - Duke Energy Corporate Services, Inc.
    - Duke Energy Business Services LLC
  - Duke Energy Registration Services, Inc.
    - Duke Energy Americas, LLC
      - Duke Energy International, LLC
  - Progress Energy, Inc.
    - Duke Energy Progress, LLC
    - Florida Progress, LLC
      - Duke Energy Florida, LLC
    - Strategic Resource Solutions Corp.
  - Piedmont Natural Gas Company, Inc.
    - Piedmont Energy Partners, Inc.
    - Piedmont Hardy Storage Company, LLC

[1] This presentation of the Duke Energy Corporation Corporate Structure is a simplified and partial legal entity view.

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C. NORTH CAROLINA CODE OF CONDUCT

(as approved by the North Carolina Utilities Commission)

This section contains the complete text of the "official" North Carolina Code of Conduct (hereinafter "Code of Conduct" or "Code"), approved by the North Carolina Utilities Commission, which governs DEC's, DEP's, and Piedmont's transactions with affiliates. This Code applies in North Carolina and South Carolina.

CODE OF CONDUCT
GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF DEP, THE PUBLIC UTILITY OPERATIONS OF PIEDMONT, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC, DEP, AND PIEDMONT

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Nonpublic information that pertains to Electric Services provided by DEC or DEP, including but not limited to information concerning electric generation, transmission, distribution, or sales, and nonpublic information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

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Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress, LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, is the current holding company parent of DEC, DEP, Piedmont, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or DEP from sources other than DEC or DEP for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

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JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Natural Gas Services: Commission-regulated natural gas sales, natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, and standby service.

Non-affiliated Gas Marketer: An entity, not affiliated with DEC, DEP, or Piedmont, engaged in the unregulated sale, arrangement, brokering, or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operation: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Personnel: An employee or other representative of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP, is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to

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G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Non-affiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated public utility operations of Duke Energy Florida, LLC ("DEF"), Duke Energy Indiana, LLC ("DEI"), Duke Energy Kentucky, Inc. ("DEK") and Duke Energy Ohio, Inc. ("DEO").

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, and Piedmont, to the extent such relationships, activities, and transactions affect the public utility operations of DEC, DEP, and Piedmont in their respective service areas. DEC, DEP, Piedmont, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DEC, DEP, or Piedmont may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, DEP, Piedmont, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable; however, to the extent that the Commission has approved or accepted a service company-to-utility or utility-to- utility service agreement or list, DEC, DEP, Piedmont, Duke Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DEC, DEP, Piedmont, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's, DEP's, and Piedmont's Nonpublic Utility Operations shall maintain separate records from those of DEC's, DEP's, and Piedmont's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

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2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC, DEP, and Piedmont may provide Customer Information to Duke Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.

(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DEC, DEP, and Piedmont or to DEC's or DEP's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC, DEP, and Piedmont retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

(c) If the Customer allows or directs DEC, DEP, or Piedmont to provide Customer Information to Duke Energy, another Affiliate, or to DEC's or DEP's Nonpublic Utility Operations, then DEC, DEP, or Piedmont shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC, DEP, or Piedmont to provide the Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2.shall be permanently posted on DEC's, DEP's and Piedmont's website(s).

(e) No DEC, DEP, or Piedmont employee who is transferred to Duke Energy or another Affiliate, shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to a signed Data Disclosure Authorization. DEC, DEP, and Piedmont shall not transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

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(f) Notwithstanding the prohibitions in this Section III.A.2.:

(i) DEC, DEP, and Piedmont may disclose Customer Information to DEBS, any other Affiliate, or a non-affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DEC, DEP, or Piedmont and upon the written agreement of the other Affiliate or non- affiliated third-party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC or DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DEC, DEP, and Piedmont may disclose Customer Information to a state or federal regulatory agency or court of competent jurisdiction if required in writing to do so by the agency or court.

(g) DEC, DEP, and Piedmont shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC, DEP, and Piedmont shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS employee may use Customer Information to market or sell any product or service to DEC's, DEP's, or Piedmont's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC, DEP, or Piedmont.

(j) DEBS employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and DEP.

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(k) Should any inappropriate disclosure of DEC, DEP, or Piedmont Customer Information occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

3. The disclosure of Confidential Systems Operation Information of DEC, DEP, and Piedmont shall be governed as follows:

(a) Such CSOI shall not be disclosed by DEC, DEP, or Piedmont to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is provided to employees of DEC or DEP for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

(ii) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.

(iii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.

(iv) The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.

(v) The CSOI is provided to employees of DEC's, DEP's, or Piedmont's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.

(vi) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.

(vii) Disclosure is otherwise essential to enable DEC or DEP to provide Electric Services to their Customers or for Piedmont to provide Natural Gas Services to its Customers.

(viii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

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(b) Any CSOI disclosed pursuant Section III.A.3.(a)(i)-(viii) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the CSOI to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vii) and (viii), DEC, DEP, and Piedmont shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;
(ii) The reasons for the disclosure; and
(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, DEP, Piedmont, and DEBS employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC, DEP, and Piedmont.

(e) Should the handling or disclosure of CSOI by DEBS, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DEC's or DEP's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet website, or (iii) other public disclosure of the data, DEC or DEP shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, and E-2, Sub 1095C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

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(f) Should any inappropriate disclosure of CSOI occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, E-2, Sub 1095C, or G- 9, Sub 682C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and DEP shall file a letter with the Commission in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's, DEP's, and Piedmont's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, Natural Gas Services, or both, DEC, DEP, and Piedmont shall not provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, DEP, Piedmont, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC, DEP, and Piedmont shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC, DEP, and Piedmont shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC, DEP, or Piedmont; provided however, that this prohibition shall not apply to employees of DEBS providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's, DEP's, or Piedmont's regulated public utility operations.

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6. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or Natural Gas Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. DEC, DEP, and Piedmont shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC, DEP, or Piedmont receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers.

11. Piedmont shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

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C. Marketing

1. The public utility operations of DEC, DEP, and Piedmont may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DEC, DEP, and Piedmont shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC, DEP, or Piedmont in any communications without the following disclaimer:

(a) "[Duke Energy Corporation/Affiliate] is not the same company as [DEC/DEP/Piedmont], and [Duke Energy Corporation/Affiliate] has separate management and separate employees";

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/DEP/Piedmont]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/DEP] or natural gas service from Piedmont."

3. Nonpublic Utility Operations may not use the names or logos of DEC, DEP, or Piedmont in communications without the following disclaimer:

"[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/DEP/Piedmont] and is not in any way sanctioned by the North Carolina Utilities Commission."

4. In addition, DEC's and DEP's Nonpublic Utility Operations may not use the names or logos of DEC or DEP in any communications without the following disclaimers:

(a) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/DEP]"; and

(b) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/DEP]."

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The required disclaimers in this Section III.C.4. must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC, DEP, or Piedmont for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC, DEP, or Piedmont, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's, DEP's, or Piedmont's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DEC, DEP, or Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC, DEP, or Piedmont shall be set at the higher of Market Value or DEC's, DEP's, or Piedmont's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS, or a Nonpublic Utility Operation to DEC, DEP, or Piedmont, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC, DEP, or Piedmont shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC, DEP, or Piedmont do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC, DEP, and Piedmont shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's, DEP's, and Piedmont's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by DEBS to DEC, DEP, Piedmont, and Utility Affiliates, the transfer price charged shall be set at DEBS' Fully Distributed Cost.

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(c) Tariffed goods and services provided by DEC, DEP, and Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC, DEP, or Piedmont to DEC, DEP, Piedmont, or the Utility Affiliates or by the Utility Affiliates to DEC, DEP, or Piedmont, shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its *Order Approving Stipulation*, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

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4. To the extent that DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS (or its successor), these Shared Services may be jointly provided to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC, DEP, and Piedmont is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC, DEP, and Piedmont. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies- of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's, and Piedmont's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC, DEP, and Piedmont incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates (other than the Customer or the Customer's designated representative or agent) shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC, DEP, or Piedmont in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

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9. DEC, DEP, and Piedmont shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy, and the other Affiliates.

2. The books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. If Piedmont supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by either DEC or DEP to generate electricity, DEC or DEP, as applicable, shall file a report with the Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

4. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC, DEP, or Piedmont with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or DEP to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or DEP, as applicable, shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

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F. Utility Billing Format

To the extent any bill issued by DEC, DEP, Piedmont, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for Electric Services or Natural Gas Services and non-Electric Services, non-Natural Gas Services, or any combination of such services, from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services and Natural Gas Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC, DEP, and Piedmont shall establish procedures to resolve potential complaints that arise due to the relationship of DEC, DEP, and Piedmont with Duke Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC, DEP, or Piedmont.

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC, DEP, or Piedmont shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC, DEP, and Piedmont shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1., any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for the EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint with the Commission or otherwise communicate with the Commission or the Public Staff regarding a complaint.

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H. Natural Gas/Electricity Competition

DEC, DEP, and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP, and Piedmont shall maintain the following minimum standards:

1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.

2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP, and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement by the Commission.

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CODE OF CONDUCT
ATTACHMENT A

DEC/DEP/PIEDMONT CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/DEP's/Piedmont's Affiliates offer products and services that are separate from the regulated services provided by DEC/DEP/Piedmont. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP/Piedmont to provide any data associated with the Customer account(s) residing in any DEC/DEP/Piedmont files, systems or databases **[or specify types of data]** to the following Affiliate(s) _____. DEC/DEP/Piedmont will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/DEP offers optional, market-based products and services that are separate from the regulated services provided by DEC/DEP. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP to use any data associated with the Customer account(s) residing in any DEC/DEP files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/DEP will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

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D. SERVICE AGREEMENT LISTS

Service Agreement lists outlining services that DEC, DEP and Piedmont may receive from their Duke Energy affiliates include the following:

- Service Company Utility Service Agreement List
- Operating Companies Service Agreement List
- Operating Companies/Non-Utility Companies Service Agreement List

For a complete list of the services related to affiliate service agreements, please refer to NCUC Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A or G-9, Sub 682A. These affiliate service agreements may also be found on the State Regulatory Compliance Portal.

In addition, DEC, DEP, and Duke Energy Florida, LLC are parties to the Nuclear Services Agreement, with the Nuclear Services Agreement List, which includes the services that DEC and DEP may receive from each other and Duke Energy Florida, LLC.

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E. GUIDELINES FOR TRANSACTIONS BETWEEN DEC/DEP/PIEDMONT AND AFFILIATES

The *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates ("Guidelines")* is an internal document developed to help employees implement the North Carolina Code of Conduct. The Guidelines may be revised from time to time as necessary to meet changing business requirements.

These Guidelines are intended to apply to all employees in dealings between DEC/DEP/Piedmont and their affiliates to assist in compliance with the North Carolina Code of Conduct, North Carolina and South Carolina state laws, and federal laws concerning affiliate transactions. Application of the affiliate rules to specific transactions may depend on the specific facts at issue. Any questions concerning the affiliate rules or these Guidelines should be directed to the subject matter experts listed later in this section.

A. DEFINITIONS

Please reference Section C. *North Carolina Code of Conduct* in this CAM for definitions. Below are some additional definitions used throughout the CAM.

FERC: Federal Energy Regulatory Commission.

NCUC: North Carolina Utilities Commission.

ORS: Office of Regulatory Staff in South Carolina.

PSCSC: Public Service Commission of South Carolina.

Public Items: Items DEC/DEP/Piedmont, in their discretion, make available at no charge to any third party, including an Affiliate, upon request.

Service Company: Duke Energy Business Services, LLC ("DEBS"), which is an affiliate that provides shared services to DEC/DEP/Piedmont and their affiliates.

Technology And Trade Secrets: For the purposes of these Guidelines, "Trade Secrets" is defined as information, including a formula, pattern, compilation, device, method, technique, or process, that: (1) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use; and (2) is the subject of efforts that are reasonable under the

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circumstances to maintain its secrecy. Technology is scientific, engineering or technical information which is patented or is a trade secret.

B. INFORMATION SHARING RESTRICTIONS

1. Customer Information

- **Customer Information may be disclosed to an Affiliate, Nonpublic Utility Operations, or any third party only with the Customer's prior consent, as described in more detail below.**
  - Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be by written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set out in Attachment A to the Code of Conduct.
  - Departments providing Customer Information to Affiliates or Nonpublic Utility Operations must retain verification of the authorization for the longer of three years or as long as the authorization remains in effect.
  - Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

  Exception: DEC/DEP/Piedmont may disclose Customer Information to Affiliates, Nonpublic Utility Operations or third parties as necessary for the Affiliate, Nonpublic Utility Operations or third party to provide goods or services to DEC, DEP or Piedmont.
  - Affiliates and/or Nonpublic Utility Operations receiving Customer Information under this exception must agree to protect the confidentiality of the Customer Information they receive. Employee training or information technology non-disclosure statements may be used to meet this requirement.
  - Agreements with third parties should provide for the protection of Customer Information.

- Customer Information may be used by DEBS employees to market or sell products or services to customers of DEC/DEP/Piedmont **only** in support of:
  - NCUC or PSCSC approved rate schedules or programs; or
  - Marketing efforts managed and supervised directly by DEC/DEP/Piedmont.

- DEBS employees with access to Customer Information may not act as an improper conduit of this information. For example, employees must not provide indirect access to the data, or recommend action based on the Customer Information, to any DEBS or other Affiliate or Nonpublic Utility Operations employees who have not been granted proper access to the information.

- ***Any improper disclosure of Customer Information requires promptly filing a statement with the NCUC describing the circumstances of the disclosure, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure, and the Legal Department must be informed of the disclosure to facilitate this notification.***

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2. Confidential Systems Operation Information

- Confidential Systems Operation Information ("CSOI") may not be disclosed to an Affiliate or Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates at the same time and in the same manner.

- ***Exceptions:***
  - The CSOI is provided to employees of DEC/DEP/Piedmont for the purpose of implementing, and operating pursuant to, the Joint Dispatch Agreement in accordance with the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A.
  - The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.
  - The disclosure is required by law or by a state or federal regulatory agency or court.
  - The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.
  - CSOI may be provided to Utility Affiliates for the purpose of sharing best practices and improving the provision of regulated utility service.
  - The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of information to be disclosed.
  - Sharing of CSOI is permitted if it is otherwise essential to enable DEC/DEP/Piedmont to provide Utility Services to its Customers, or for compliance with the Sarbanes-Oxley Act of 2002.
  - However, certain reporting requirements are triggered by use of this exception. ***Consult with the Legal Department prior to sharing Operation Information under this exception.***
  - Employees receiving CSOI under these exceptions must agree to protect the confidentiality of information they receive and may not improperly share this information with other Affiliate or Nonpublic Utility Operation employees who are not permitted to have access to this information. Employee training or information technology non-disclosure statements may be used to communicate these requirements.
  - DEC/DEP/Piedmont and DEBS's employees with access to CSOI may not act as an improper conduit of this information. For example, employees must not provide indirect access to the data, or recommend action based on the CSOI, to any DEBS or other Affiliate or Nonpublic Utility Operations employees who have not been granted proper access to the information.

- ***Any improper disclosure of CSOI requires promptly filing a statement with the NCUC in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure, and the Legal Department must be informed of the disclosure to facilitate this notification.***

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3. Market and Transmission Information

- The FERC Affiliate Restrictions and the Standards of Conduct prohibit the disclosure of DEC/DEP/Piedmont's market information and non-public transmission information to a market-regulated power sales affiliate (otherwise known as a non-regulated affiliate). FERC defines market information as: "non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates." The FERC Standards of Conduct prohibit the disclosure of DEC/DEP/Piedmont's non-public transmission system information to marketing function employees. Information regarding the Standards of Conduct and inappropriate disclosures is explained in Duke Energy's FERC Standards of Conduct Compliance Procedures found at www.ferc.duke-energy.com.
- Any handling or disclosure of DEC/DEP/Piedmont's market information or non-public transmission information by DEBS or its employees which results in (a) a violation of the FERC Affiliate Restrictions or Standards of Conduct, (b) the posting of such data on an OASIS or other Internet website, or (c) other public disclosure of the data, requires that DEC/DEP promptly file a statement with the NCUC. ***The Legal Department must be informed of any such occurrence to facilitate this notification.***

C. AFFILIATE AGREEMENTS

1. Filing Requirements

- Before DEC/DEP/Piedmont may make payment to an Affiliate for services not already approved, it must obtain prior NCUC approval.
- DEC/DEP/Piedmont must file all other affiliate agreements with the NCUC for notice. This notice must be at least 60 days in advance of the transfer of DEC/DEP/Piedmont's technology or trade secrets, provided, however, that DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other.
- Before filing an affiliate agreement with the NCUC, DEC/DEP/Piedmont must submit it, unsigned, to the Public Staff -at least 15 days in advance for informal review.
- DEC/DEP/Piedmont must make available to the ORS copies of affiliate agreements involving payment by DEC/DEP/Piedmont to an Affiliate.
- **Service Level Agreements ("SLA")** may be considered affiliate agreements that trigger these filing and approval requirements. ***Contact the Legal Department before entering into an SLA between DEC/DEP/Piedmont and any Affiliate.***
- DEC/DEP/Piedmont must obtain PSCSC approval prior to the transfer of any utility asset valued at greater than $1 million to any party; and must provide 30 days advance notice to the NCUC prior to the transfer of any utility asset with a gross book value in excess of $10 million to any party.
- Under both North and South Carolina law, DEC/DEP/Piedmont bear the burden of showing that affiliate transactions are reasonable and prudent.

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➢ Existing Agreements

- Copies of filed affiliate agreements are available for review on the State Regulatory Compliance Portal.

- On August 26, 2016, DEC, DEP, and Piedmont jointly filed in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A the following affiliate agreements to which they were parties:
  - ➢ Service Company Utility Service Agreement
  - ➢ Operating Companies Service Agreement
  - ➢ Operating Companies/Non-Utility Companies Service Agreement
  - ➢ Tax Sharing Agreement
  - ➢ Intercompany Asset Transfer Agreement
  - ➢ Utility Money Pool Agreement

- DEC and DEP are also parties to the Nuclear Services Agreement, which they jointly filed at the NCUC on December 1, 2011, in Docket Nos. E-2, Sub 998A and E-7, Sub 986A.

- Brief descriptions of these agreements follow:
  - ➢ Service Company Utility Service Agreement – It is expected that Franchised Electric & Gas employees whose job responsibilities involve providing certain services to different operating companies will be employed by DEBS and will provide services to DEC/DEP/Piedmont as well as the other Utility Affiliates[1] under this agreement.
  - ➢ Operating Companies Service Agreement – Under this agreement, DEC/DEP/Piedmont and their Utility Affiliates may provide certain services to each other. With the exception of DEC/DEP/Piedmont providing services for each other, the Utility Affiliates will request services from each other using Service Request for Affiliates form.
  - ➢ Operating Companies/Non-Utility Companies Agreement – Under this agreement, DEC/DEP/Piedmont and their non-utility Affiliates may provide certain services to each other under a Service Request for Affiliates form.
  - ➢ Nuclear Services Agreement – Under this agreement, DEC, DEP, and Duke Energy Florida, LLC, may provide certain services to each other to support management and operation of the nuclear plants.
  - ➢ Tax Sharing Agreement – The Tax Sharing Agreement, which is an agreement for the filing of consolidated income tax returns and for allocation of consolidated income tax liabilities and benefits.
  - ➢ Intercompany Asset Transfer Agreement – The Intercompany Asset Transfer Agreement, which is an agreement that allows DEC, DEP, Piedmont and their regulated utility affiliates to transfer assets to one another.
  - ➢ Utility Money Pool Agreement – The Utility Money Pool Agreement, which is an agreement that allows the parties to borrow funds on a short-term basis and to create a cash management program.

[1] "Utility Affiliates" means the regulated public utility operations of Duke Energy Indiana, LLC, Duke Energy Kentucky, Inc., Duke Energy Florida, LLC, and Duke Energy Ohio, Inc.

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- Pursuant to North Carolina Regulatory Condition No. 5.4, DEC/DEP/Piedmont filed lists with the NCUC of the services they intend to obtain from their affiliates under the affiliate Service Agreements. Before receiving any services that are not on the appropriate list, DEC/DEP/Piedmont must give the NCUC **15 days advance notice.**

- With the exception of the Nuclear Services Agreement, which was last filed with the NCUC on June 30, 2014, these agreements supersede in their entirety DEC's affiliate service agreements previously filed in Docket Nos. E-7, Sub 795A and E-7, Sub 810; and DEC's and DEP's affiliate service agreements previously filed in Docket Nos. E-7, Sub 986A and E-2, Sub 998A.

- ***Contact the Legal Department before obtaining or providing goods or services from or to an Affiliate that are not covered by Affiliate Agreements.***

D. COST ALLOCATION & TRANSFER PRICING RULES

1. Cost Allocations

- **Corporate Governance and Shared Services**
  - DEC/DEP/Piedmont and their Affiliates may use joint corporate oversight, governance, corporate support and utility support systems and personnel. These services are provided by DEBS under the Service Company Utility Service Agreement (see Affiliate Agreements above).

  - Costs must be allocated or charged back on a fully distributed cost basis and are subject to review by state regulators. Charging methods are described in the applicable Service Agreement.

  - DEC/DEP/Piedmont must perform periodic evaluations that show shared services are cost-beneficial to it on a service by service basis.

- **Joint Purchases**
  - ***Generally:*** DEC/DEP/Piedmont and their Utility Affiliates may capture economies of scale in joint purchases of goods and services (*excluding*: electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement – see special provision below) or the joint development of an asset if (a) the purchase results in cost savings to DEC/DEP/Piedmont's Customers, and (b) the costs are allocated appropriately and an audit trail maintained.

  - ***Coal and Natural Gas:*** DEC/DEP/Piedmont and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas for consumption, if these purchases result in cost savings to DEC/DEP/Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits

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clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's and Piedmont's affiliated transaction reports filed with the Commission.

- ***The Legal Department must be informed of any such transfer to facilitate this notification.***

2. Transfer Pricing Rules

- **Types of Transactions**
  - **Affiliate or Nonpublic Utility Operation Providing Goods or Services to DEC/DEP/Piedmont**
    - Refer to "Filing Requirements" above.
    - DEC/DEP/Piedmont must perform a "make or buy" analysis.
    - For goods and services provided to DEC/DEP/Piedmont by Duke Energy Corporation, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer prices should be the lower of the supplier's fully distributed cost or market value.
    - For goods and services provided to DEC/DEP/Piedmont by each other or another Utility Affiliate, the transfer price should be the supplier's fully distributed cost.
    - Transfer pricing rules apply to Affiliates acting as subcontractors to other Affiliates providing goods or services to DEC/DEP/Piedmont.

  Exceptions:
    - Corporate governance, corporate services and utility support services (discussed above) may be provided at fully distributed cost.

  - **DEC/DEP/Piedmont Providing Utility Services to Affiliates/ Nonpublic Utility Operations**
    - Refer to "Filing Requirements" above.
    - Tariffed services provided by DEC/DEP/Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Utility Services.
    - Untariffed services provided by DEC/DEP/Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation should be transferred at the higher of market value or DEC's, DEP's, or Piedmont's fully distributed cost.
    - Untariffed services provided by DEC/DEP/Piedmont to each other or another Utility Affiliate should be transferred priced at the supplier's fully distributed cost.
    - Loaned Employees
      - DEC/DEP/Piedmont may assign an employee to an Affiliate or Nonpublic Utility Operations if the assignment does not interfere with or impair DEC/DEP/Piedmont's utility responsibilities or business operations.
      - Responsibility for all liabilities to third parties and any legal or other related expenses that arise in connection with the work of the employee lies with the Affiliate.

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- **DEC/DEP/Piedmont Providing Goods/Assets to Affiliates/Nonpublic Utility Operations and the transfer or Use of Utility Assets/Goods not subject to Intercompany Asset Transfer Agreement**

  - Tariffed goods provided by DEC/DEP/Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operations shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services.
  - All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.
  - All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC/DEP/Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.
  - All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its *Order Approving Stipulation*, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.
  - Untariffed goods provided by DEC/DEP/Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation should be transferred at the higher of market value or DEC/DEP/Piedmont's fully distributed cost.
  - Determining the appropriate price requires consideration of fully distributed cost, market price evaluation and an appropriate allocation methodology (see below).
  - Affiliates/Nonpublic Utility Operations may use DEC/DEP/Piedmont's goods or assets without charge in connection with the performance of work for DEC/DEP/Piedmont if they would permit a third-party supplier to have the same access to such goods or assets without Operations without charge.
  - DEC/DEP/Piedmont may share Public Items with its Affiliates/Nonpublic Utility Operations without charge.
  - No materiality threshold on transfers to/from non-Utility or non-Regulated Utility affiliates.

  - ***In each instance, the Legal Department must be contacted prior to any such***

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transfer to facilitate an asset transfer agreement.

- **Transfer of Technology or Trade Secrets**
  - ***Transfer, including sublicense, of technology or trade secrets by DEC/DEP/Piedmont to an Affiliate requires 60 days prior notice to the NCUC***. Software developed by *or on behalf of* DEC/DEP/Piedmont typically constitutes technology or trade secrets, which may also include proprietary manuals, technical processes, etc. The following procedure should be followed in the event of a request to transfer and provide use of technology or trade secrets to an Affiliate:
    - Notice: The Code of Conduct requires 60-days' notice to the NCUC in advance of the transfer of technology or trade secrets, unless the transfer is between DEC/DEP/Piedmont. If circumstances warrant, DEC/DEP/Piedmont may request a waiver of the advance notice requirement, but the notice period CANNOT be less than 20 business days. The department (or its department financial contact) transferring or allowing use of the DEC/DEP/Piedmont technology or trade secret to an Affiliate must notify the Legal or Carolinas Rates & Regulatory Strategy Departments before the beginning of the advance notice period. Details of the transaction, including description and appropriate compensation support, sufficient to make the filing with the NCUC must be provided in time to meet the notice requirement. If the transferring department requires assistance with determining the pricing methods or other transfer requirements, additional time to consult with the Legal or Carolinas Rates & Regulatory Strategy Departments should be allowed in advance of the notice period.
    - Transfer pricing: Generally, DEC/DEP/Piedmont are compensated for such technology and trade secret transfers at the higher of market or fully-distributed cost, subject to the conditions and/or exceptions discussed in this section. Market and cost comparison procedures to be followed (as well as applicable exceptions) are further discussed in the "Pricing Rules Compliance Documentation – Transfer or Sharing of Goods/Products" section below. The transferring department, along with the department financial contact if necessary, must ensure that the appropriate accounting entries are recorded to compensate DEC/DEP/Piedmont according to the transfer pricing requirements.

      Supporting documentation describing the technology or trade secret transferred, as well as the pricing support documentation must be maintained by the transferring department.

- **Sharing Customer Information or CSOI**
  - Sharing DEC/DEP/Piedmont's Customer Information or CSOI is strictly limited, as described in Sections B.1 & B.2 above. In the event Customer Information or CSOI is provided to an affiliate (or third party other than the Customer or the Customer's designated representative or agent), the North Carolina Code of Conduct requires that all costs incurred in assembling, compiling, preparing, or furnishing the information be recovered from the requesting party.

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- "All costs" means fully-distributed cost and includes any overhead or allocable cost associated with the labor cost incurred to provide the information as well as any incremental systems, materials/supplies, or other costs identified with the transaction.

Although the Customer Information or CSOI is specific to DEC/DEP/Piedmont, the employees providing the Customer Information or CSOI, or providing a service using DEC/DEP/Piedmont Customer Information or CSOI, may be utility or Service Company employees. Charging fully distributed cost must have the effect of removing the applicable labor and other dollars from either DEC/DEP/Piedmont direct charges, or from a pool of Service Company dollars, which are otherwise direct-charged, distributed, or allocated to DEC/DEP/Piedmont. The following process should be followed to bill or charge costs associated with providing Customer Information or CSOI:

- The department or group providing the Customer Information or CSOI must develop a method to price the transaction or activity (if the activity is recurring) appropriately. For example, a per-transaction price may be developed by observing the average time involved in completing a service using Customer Information, applying a proportionate labor rate plus associated overheads, then multiplying by a number of transactions (tracked or estimated) for the accounting period, to compute a charge to the Affiliate or third party. Less complex methods may be appropriate to charge for one-time or infrequent transactions.
- The department or group providing the Customer Information or CSOI will provide sufficient detail to its department financial contact to enable the contact to make the appropriate journal entry to record the charge (or to bill the third party if applicable). The department financial contact must ensure that the appropriate accounting entries are recorded.
- Supporting documentation describing the transaction, as well as the pricing determination support, must be maintained by the department providing the Customer Information or CSOI or the applicable department.

- **Wholesale Power Sales or Purchases**
  - Require FERC approval.
  - May require Advance Notice to NCUC and approval by State Commissions, depending on the circumstances.

- **Pricing Rules Compliance and Documentation**
  - **Performance of Services**
    - Every DEC/DEP/Piedmont department that performs services for Affiliates should conduct, or cause to be prepared, a periodic market analysis to compare the department's current fully distributed cost to the equivalent market prices. Similarly, when it obtains services from an Affiliate (other than Corporate Governance and Shared Services or under the Utility-to-Utility exception),

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each DEC/DEP/Piedmont department should perform, or ensure that the Affiliate performs a market comparison for such services and documents its rationale for selecting the Affiliate.

- **Transfer or Sharing of Goods/Products**
  - DEC/DEP/Piedmont should conduct periodic market to current cost comparisons for utility assets such as facilities, vehicles, equipment and information technology property, which are shared with or used by Affiliates. The market versus cost evaluation is applicable to any such assets provided on an ongoing basis or as the result of an individual transaction. Similarly, when DEC/DEP/Piedmont uses assets owned by an Affiliate, they should perform or ensure that the Affiliate performs a market comparison for such assets.

For the transfer or sharing of items developed, created or constructed by DEC/DEP/Piedmont or an Affiliate (regardless of whether the item is a capital asset), DEC/DEP/Piedmont departments should perform a market comparison to determine the appropriate price, taking into consideration the following as applicable:

- The fully distributed cost to DEC/DEP/Piedmont or the affiliate to develop the item; the appropriate allocation of such costs for items that will be shared, such as software; the market price to purchase the item "off the shelf", if available; and the market price to hire a professional to develop the item.

Exceptions:

- ***No Comparable Market Exception***. If no comparable market exists, the goods or services should be priced at fully distributed costs. A DEC/DEP/Piedmont department relying on this exception should document how it determined that no comparable market exists.

- ***Joint Purchase/Development Exception.*** The Code permits the use of shared corporate governance and shared support and permits joint purchases among DEC/DEP/Piedmont and their affiliates. Therefore, Duke Energy may establish a project to jointly develop an item to be used by multiple business units, including DEC/DEP/Piedmont, provided that the costs are allocated appropriately and accounting records are maintained to reflect the cost sharing. Similarly, DEC/DEP/Piedmont and their affiliates may jointly procure goods or services from third-party suppliers.

- ***Use of Assets in the Performance of Services.*** Affiliates may use DEC/DEP/Piedmont goods or assets without charge in connection with the performance of work for DEC/DEP/Piedmont if DEC/DEP/Piedmont would permit a third-party supplier to have the same access to such goods or assets without charge.

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E. REGULATORY OVERSIGHT

- DEC/DEP/Piedmont are required to file a detailed Carolinas CAM and Annual Affiliate Transactions Report with the NCUC. The CAM and Report are subject to regular audit by the Public Staff.
- DEC/DEP/Piedmont are also required to maintain information on affiliate transactions for review by the PSCSC and ORS upon request.
- Corporate Audit Services performs an annual audit of Affiliate transactions.
- Independent audit of transactions under the Service Agreements occurs no less than every 2 years.

F. COMPLAINT PROCEDURE

The Code of Conduct requires DEC/DEP/Piedmont to follow established procedures to resolve any complaints that may arise due to the relationship of DEC/DEP/Piedmont with Duke Energy Corporation, its other Affiliates, or its Nonpublic Utility Operations. Complaints could originate from any source, including customers, potential suppliers, alliance partners, competitors, etc., or could be referred to DEC/DEP/Piedmont by the NCUC, PSCSC, Public Staff, or ORS. The following steps comprise the procedure to follow in the event of a complaint:

- Any verbal or written complaints will be referred to the Duke Energy Regulatory Affairs contact below (written complaints forwarded by the NCUC, PSCSC, Public Staff or ORS are automatically received by the Regulatory Affairs team).
- The Regulatory Affairs team will provide written notice to the complainant within 15 days indicating that the complaint was received.
- The Regulatory Affairs team will conduct or coordinate the investigation of the complaint, provide the results of such investigation to the Legal Department for review and input, and report back the status or results of the review to the complainant within 60 days of receiving the complaint.
- A log of complaints received and the related documents will be maintained by the Regulatory Affairs team for audit purposes.

Note: Any complaints received via the Ethics Line will be handled separately according to the procedures established for Ethics Line.

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SUBJECT MATTER EXPERTS & RESOURCES

Name	Area	Phone
Kendrick Fentress	Legal – NC State Rules	919.546.6733
Rebecca Dulin	Legal – SC State Rules	803.988.7130
Ann Warren	Legal – FERC Rules	704.382.2108
Alan Hutcherson	Corporate Compliance – State Rules	704.382.5667
Chris Whicker	Corporate Compliance – FERC Rules	704.382.2869
Laura Bateman	DEC and DEP Rates & Regulatory	919.546.3324
Pia Powers	Piedmont Rates & Regulatory	704.731.4259

Note: Department financial contacts referred to in the guidelines above are in the Financial Planning and Analysis organization.

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F. SHARED SERVICES COST DISTRIBUTION PROCESS

Services designated as "shared support," for purposes of the North Carolina Regulatory Conditions and Code of Conduct, are Services that are corporate or general utility in nature and are used by multiple business units. These services are provided pursuant to a Utility Service Agreement filed with the NCUC.

The list of services conforms to the service category descriptions included in Attachment 2 of the Service Company Utility Service Agreement, and represents the shared services offered that DEC, DEP, and Piedmont intend to obtain under this agreement. DEC, DEP, and Piedmont are required by the North Carolinas Utilities Commission to update the list of services as necessary. Interim changes to this list require filing with the Commission, with 15 days advance notice of the proposed changes.

The shared services cost distribution process is the method by which costs of the Services Company are fully distributed.

The objectives of the cost distribution process are to:

- Meet regulatory requirements.
- Ensure that each affiliate shares in and is appropriately charged for the relevant shared services costs.
- Assist affiliates in understanding the cost drivers and basis for allocation of shared services costs that affect their operating results.
- Provide an accounting model whereby affiliates can see how much is allocated to them for each shared service.

Costs for shared services are distributed to affiliates within Duke Energy through *(i)* direct charges, *(ii)* distribution or *(iii)* allocation. Costs are direct charged to the extent possible. Costs that cannot be direct charged can be distributed to the applicable business units using specific percentages if known. Costs that cannot be direct charged or distributed are allocated to the business units receiving the benefit using reasonable allocation methods as described in the "Shared Services Cost Distribution Details" section of this manual. Services are charged to

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Affiliates on a fully distributed cost basis and include labor and non-labor costs. As part of a fully distributed cost, an overhead component is charged to Affiliates as a percentage of Service Company labor costs, whether direct charged, distributed or allocated. This overhead represents the cost of shared services provided by shared services employees.

The Corporate Accounting group is responsible for developing the following allocation factors, which serve as the basis for the allocation of costs that have not been direct charged or distributed. Final allocation factors distributing costs to each affiliate sum to 100% for each cost pool, thus clearing out 100% of costs to be allocated each month. Interim adjustments to allocation factors are made only for material transactions, such as an acquisition or divestiture of an affiliate, and for major company reorganizations.

Corporate Accounting reviews Service Company allocation factors annually. Typically during the budget process, rates are recalculated and implemented for actuals at the beginning of the following year. These rates are reflected in the Service Company allocation rate schedule included in the Cost Allocation Manual.

The Service Company also charges for certain services under the Service Company Utility Service Agreement. Types of pass-through costs typically handled by the Service Company may include:

1. Finance & Accounting Services
2. Insurance Premium Expense
3. Advertising Expense
4. Community Relations Projects
5. Donations
6. Employee Benefits Expense
7. Dues / Subscriptions
8. Merger Execution Costs
9. Research & Development
10. Miscellaneous Lease / Rent Expense

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G. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH THE SERVICE COMPANY

On a regular basis, Service Company employees provide support to DEC/DEP/Piedmont. All Service Company resources used to support DEC/DEP/Piedmont must properly charge the respective utility through *(i)* direct charges, *(ii)* distribution or *(iii)* allocation. Charging fully distributed cost to DEC/DEP/Piedmont is normally accomplished with the application of a percentage loaded on direct labor. Service Company management is accountable for employees appropriately charging their costs. An Affiliate Rules and Transactions Computer Based Training ("CBT") (emphasis on DEC/DEP/Piedmont) is available in the Training Connection on the Portal.

The following procedure addresses employees' and management's responsibilities.

A. General Guidelines

1. Consistent with Regulatory Condition No. 5.5, hours worked by Service Company employees in direct support of DEC/DEP/Piedmont are charged directly to the respective utility to the maximum extent practicable.
2. First-line supervisors should review and approve, when appropriate, source documentation resulting in a charge by Service Company to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to DEC/DEP/Piedmont.
4. Service Company to DEC/DEP/Piedmont transactions are covered under the Service Company Utility Agreement.

B. Time Reporting

When a Service Company employee provides direct support to DEC/DEP/Piedmont: Consistent with Regulatory Condition No. 5.5, hours worked by Service Company employees in direct support of DEC/DEP/Piedmont are charged directly to the respective utility to the maximum extent practicable.

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1. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for vacation carryover or paid supplemental compensation.
2. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads of fringe benefits, payroll taxes, incentive pay and unproductive time, as applicable.

C. Labor Allocations

Service Company employees provide services to DEC/DEP/Piedmont at fully distributed cost. Allocation of costs described in items 1 through 5 below are applied as a cost factor to labor charged to DEC/DEP/Piedmont. Below are the various cost components of labor loads. The rates for these items may be adjusted during the year to properly accrue the associated actual or anticipated cost.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement, and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among Affiliates.

2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among Affiliates.

3. Incentive Allocation

Incentives are accrued via a loading factor applied to labor charges.

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4. Unproductive Cost Allocation

An unproductive cost allocation is applied to productive labor charges by the Service Company employee. Service Company allocates unproductive costs pro rata to productive labor, either via a monthly ratio or standard rates.

5. Service Company Overhead

A Service Company overhead rate is based on historical enterprise and governance overhead charged to Regulated Utilities in the following functions: Information Systems, Transportation, Human Resources, Materials Management, Accounting, Public Affairs, Legal, Finance, Facilities, Internal Auditing, Environmental, Health and Safety, Investor Relations, Planning, and Executive.

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H. SHARED SERVICES COST DISTRIBUTION DETAILS

See the following charts for descriptions of services provided and associated allocation methods and factors

2019 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Comm Trans-Elec	Total Electric Utilities
Information Systems	Development and support of mainframe computer software applications.	*Number of Central Processing Unit Seconds Ratio/Millons of Instructions per Second*	ENMF	Information Systems	Mainframe Svcs Ent	ENTCPUMFR	S05	67.48	-	-	12.10	2.07	10.50	-	92.15
			PRMF	Information Systems	Mainframe Svcs Ent PE	PRECPUMFR	P05	-	57.52	42.48	-	-	-	-	100.00
			DEMF	Information Systems	Mainframe Svcs Ent DUK	DENTCPUMFR	D05	46.39	15.08	11.14	8.31	1.42	7.21	-	89.55
			PUMF	Information Systems	Mainframe Svcs Utility PE	PRUCPUMFR	P11	-	57.51	42.49	-	-	-	-	100.00
	Procurement and support of personal computers and related network and software applications.	*No. of Personal Computer Workstations Ratio*	ENWS	Information Systems	Worksta Svcs Enterprise	ENTWKSWKS	S06	83.52	-	-	7.97	0.68	2.28	-	94.45
			PRWS	Information Systems	Worksta Svcs Enterprise PE	PREWKSWKS	P06	-	64.95	33.82	-	-	-	-	98.77
			DWSE	Information Systems	Worksta Svcs Enterprise DUK	DENTWKSWKS	D06	42.38	29.23	15.22	4.04	0.36	1.15	-	92.38
			PUWS	Information Systems	Worksta Svcs Utility PE	PRUWKSWKS	P12	-	64.96	33.82	-	-	-	-	98.78
	Development and support of distributed computer software applications (e.g., servers).	*Number of Info Systems Servers Ratio*	ENSS	Information Systems	Server Svcs Enterprise	ENTSYSSVR	S07	53.40	-	-	21.39	3.70	11.46	-	89.95
			PRSS	Information Systems	Server Svcs Enterprise PE	PRESYSSVR	P07	-	44.65	53.82	-	-	-	-	98.47
			DESS	Information Systems	Server Svcs Enterprise DUK	DENTSYSSVR	D07	29.80	16.52	19.93	11.92	2.06	6.38	-	86.61
			UTSS	Information Systems	Server Svcs Utility	UTISYSSVR	S13	30.03	16.67	20.10	12.02	2.08	6.44	-	87.34
			PUSS	Information Systems	Server Svcs Utility PE	PRUSYSSVR	P13	-	44.65	53.82	-	-	-	-	98.47
	Installation and operation of communications systems.	*Number of Employees Ratio*	ENTS	Information Systems	Telecom Svcs Enterprise	ENTEMPTEL	S33	76.68	-	-	12.54	1.13	3.24	-	93.59
			PRTS	Information Systems	Telecom Svcs Enterprise PE	PREEMPTEL	P33	-	63.24	35.52	-	-	-	-	98.76
			DETS	Information Systems	Telecom Svcs Enterprise DUK	DENTEMPTEL	D33	38.57	26.57	14.92	6.31	0.57	1.64	-	88.58
			DUTS	Information Systems	Telecom Svcs Utility	DUTIEMPTEL	D34	39.27	27.07	15.18	6.42	0.58	1.67	-	90.19
			UTTS	Information Systems	Telecom Svcs Utility	UTIEMPTEL	S34	79.51	-	-	13.01	1.18	3.37	-	97.07
			PTSU	Information Systems	Telecom Svcs Utility PE	PRUEMPTEL	P34	-	63.24	35.52	-	-	-	-	98.76
			ENHD	Information Systems	Helpdesk Services	ENTEMPHLP	S33	76.68	-	-	12.54	1.13	3.24	-	93.59
			DEHD	Information Systems	Helpdesk Services DUK	DENTEMPHLP	D33	38.57	26.57	14.92	6.31	0.57	1.64	-	88.58
			PRHD	Information Systems	helpdesk Services PE	PREEMPHLP	P33	-	63.24	35.52	-	-	-	-	98.76
	Information systems management and support services.	*No. of Personal Computer Workstations Ratio*	ENMA	Information Systems	ITS Mgt & Apps Svcs Ent	ENT3FFITM	S35	77.07	-	-	7.34	0.63	2.09	-	87.13
			DEMA	Information Systems	ITS Mgt & Apps Svcs Ent DE	DENT3FFITM	D35	42.38	29.23	15.22	4.04	0.36	1.15	-	92.38
			PRMA	Information Systems	ITS Mgt & Apps Svcs Ent PE	PRE3FFITM	P35	-	64.95	33.82	-	-	-	-	98.77
			UTMA	Information Systems	ITS Mgt & Apps Utility	UTI3FFITM	S36	86.39	-	-	8.23	0.70	2.34	-	97.66
			DELH	Information Systems	Duke Energy Lighthouse	DUWKSITM	D11	43.11	29.73	15.48	4.10	0.36	1.17	-	93.95
			DUMA	Information Systems	ITS Mgt & Apps Svcs Util DE	DUT3FFITM	D36	42.38	29.23	15.22	4.04	0.36	1.15	-	92.38
								-	-	-	-	-	-	-	-
Meters	Procures, tests and maintains meters.	*Number of Customers Ratio*	DEMS	Meters	Meter Svcs Utility DE	DUTICUSMTR	D14	28.09	17.02	19.49	8.87	1.53	7.71	-	82.71
			UMMS	Meters	Meter Svcs Util MWonly Elec/Gas	UTMCUSMTR	S60	-	-	-	37.22	6.41	32.34	-	75.97
			UEMS	Meters	Meter Svcs Util MW Elec	UTECUSMTR	S58	-	-	-	48.99	8.43	42.58	-	100.00
								-	-	-	-	-	-	-	-
Transportation	Procures and maintains vehicles and equipment.	*Number of Employees Ratio*	DUVE	Transportation	Transp Vehicles Utility DE	DUTIEMPVEH	D10	39.76	27.33	15.45	6.58	0.73	1.59	-	91.44
			UMVE	Transportation	Transp Vehicles Util MW only	UTMEMPVEH	S65	-	-	-	68.31	7.55	16.56	-	92.42
								-	-	-	-	-	-	-	-
	Procures and maintains aircraft and equipment.	*Three Factor Formula*	DGAV	Transportation	Transp Aviation Gurnce	DGOV3FFAVI	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
			DEAV	Transportation	Transp Aviation Svcs Ent DE	DENT3FFAVI	D03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	UTTR	Electric System	ESS Elec Tran Utility	UTICMTETR	S15	40.89	19.53	15.43	16.60	0.33	7.22	-	100.00
			UMTR	Electric System Maintenance	ESS Elec Tran Utility - MW	UTICMTEMW	S96	-	-	-	68.72	1.39	29.89	-	100.00
								-	-	-	-	-	-	-	-
	Services related to distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	UTDI	Electric System	ESS Elec Dist Utility	UTICMTEDT	S16	39.27	25.58	16.38	11.38	1.10	6.29	-	100.00
			UMDI	Electric System Maintenance	ESS Elec Dist Utility MW only	UTMCMTEDT	S57	-	-	-	60.62	5.85	33.53	-	100.00
								-	-	-	-	-	-	-	-
Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*						-	-	-	-	-	-	-	-
			PUSD	Marketing and	M&CR SALES & Demand Util PE	PRUTSALMCR	P17	-	46.62	53.38	-	-	-	-	100.00
			NET	Marketing and Customer Relations	Customer Strategy P&S	UTISALNET	S75	60.79	-	-	19.21	3.31	16.69	-	100.00
			STD	Marketing and Customer Relations	Standard Services	UTISALSTD	S17	54.09	-	-	17.09	2.94	14.85	-	88.97
			MSST	Marketing and Customer Relations	Mkt Sol - SrvCo Duke Standard	UTMSCLSTD	D98	60.79	-	-	19.21	3.31	16.69	-	100.00
			UMSD	Marketing and Customer Relations	M&CR Standard Prod Util MWonly	UTMSALNET	S68	-	-	-	37.22	6.41	32.34	-	75.97
			UMNT	Marketing and Customer Relations	M&CR Net Product Util MW only	UTMSALSTD	S68	-	-	-	37.22	6.41	32.34	-	75.97

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2019 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Comm Trans-Elec	Total Electric Utilities
Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*	UESD	Marketing and Customer Relations	M&CR Sls&Dmnd Util MW Elec only	UTMSALMCR	S66	-	-	-	48.99	8.43	42.58	-	100.00
			UGSD	Marketing and Customer Relations	M&CRSale&Demand Utl MW Gas only	UTGSALMCR	S67	-	-	-	-	-	-	-	-
			DTNT	Marketing and Customer Relations	M&CR Elec Only Util DE	DUTICUSMCR	D75	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
			UTNT	Marketing and Customer Relations	M&CRSale&Demand Utl MW Gas only	UTISANET	S75	60.79	-	-	19.21	3.31	16.69	-	100.00
								-	-	-	-	-	-	-	-
	Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	UTMR	Marketing and Customer Relations	M&CR Mtr Rdg&Pmt Proc Util	UTICUSPMT	S37	54.09	-	-	17.09	2.94	14.85	-	88.97
			DUMR	Marketing and Customer Relations	M&CR Customers Util ND	DUTICUSPMT	D37	28.09	17.02	19.49	8.87	1.53	7.71	-	82.71
			DUMS	Marketing and Customer Relations	Mkt Sol Srvco Utilities Std	DUTICUSPAY	D95	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
			UMMR	Marketing and Customer Relations	M&CR MtrRdg&PmtPrc Util MWonly	UTMCUSPMT	S60	-	-	-	37.22	6.41	32.34	-	75.97
			UCMR	Marketing and Customer Relations	M&CR MtrRdgPmtPrc DEO DEK only	UTOCUSPMT	S59	-	-	-	-	10.21	51.52	-	61.73
			DCTH	Marketing and Customer Relations	M&CR Customers Util ND	DGDVCUSCTA	DG5	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
	Customer services including the operation of call center.	*Number of Customers Ratio*	UEMR	Marketing and Customer Relations	M&CR MtrRdg&PmtPrc Util	UTECUSPMT	S58	-	-	-	48.99	8.43	42.58	-	100.00
			UMPD	Marketing and Customer Relations	M&CR Util MW PD	UTMCUSMPD	S69	-	-	-	37.22	6.41	32.34	-	75.97
			DCIS	Marketing and Customer Relations	M&CR Cust Info Sys_Util	DUTICUSSYS	T05	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
			UWPD	Marketing and Customer Relations	M&CR PD DEO/DEK E/G	UTMCUSWPD	S70	-	-	-	-	10.21	51.52	-	61.73
	Costs associated with Smart Grid activities	*Number of Customers Ratio*	USGA	Marketing and Customer Relations	M&CR Smart Grid All E/G	UTICUSSG	S76	54.09	-	-	17.09	2.94	14.85	-	88.97
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only	UTECUSSG	S77	60.79	-	-	19.21	3.31	16.69	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G	DUTICUSSG	D89	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only	DUTECUSSG	D93	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES O&M	UTICUSSES	S84	54.09	-	-	17.09	2.94	14.85	-	88.97
			USGA	Marketing and Customer Relations	M&CR Smart Grid Util Capital	UTICUSSG	S80	54.09	-	-	17.09	2.94	14.85	-	88.97
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only Capital	UTECUSSG	S81	60.79	-	-	19.21	3.31	16.69	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G - Capital	DUTICUSSG	D90	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only- Capital	DUTECUSSG	D94	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES Cap	UTICUSSES	S85	54.09	-	-	17.09	2.94	14.85	-	88.97
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G	DUTICUSGS	T01	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G - Capital	DUTICUSGS	T02	31.75	19.25	22.04	10.03	1.73	8.72	-	93.52
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric	DUTECUSGS	T03	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric - Capital	DUTECUSGS	T04	33.96	20.58	23.56	10.73	1.85	9.32	-	100.00
								-	-	-	-	-	-	-	-
Electric Transmission & Distribution Engineering & Construction - Designs and monitors construction of electric transmission and distribution lines and substations. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.	Transmission engineering and construction:	*(Electric Transmission Plant's) Construction - Expenditures Ratio*	UTET	Electric Transmission	Eng & Constr ET Utility	UTICONETR	S18	23.10	14.97	39.06	10.57	1.15	11.15	-	100.00
			UEET	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ET Util MW only	UTMCONETR	S62	-	-	-	46.22	5.03	48.75	-	100.00
								-	-	-	-	-	-	-	-
	Distribution engineering and construction:	*(Electric Distribution Plant's) Construction - Expenditures Ratio*	UTED	Electric Transmission	Eng & Constr ED Utility	UTICONEDT	S30	29.27	23.21	21.79	13.38	1.57	10.78	-	100.00
			UEED	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ED Util MW only	UTMCONEDT	S61	-	-	-	51.98	6.12	41.90	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-

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2019 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Comm Trans-Elec	Total Electric Utilities
Power Engineering & Construction	Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	*(Electric Production Plant's) Construction - Expenditures Ratio*	UTEC	Power Engineering & Construction	Eng & Constr Pwr Prod Util	UTICONPWR	S25	34.49	30.03	15.59	14.05	5.84	-	-	100.00
			UEEC	Power Engineering & Construction	Eng&Constr Pwr Prod Util MW only	UTMCONPWR	S63	-	-	-	70.63	29.37	-	-	100.00
			UGEG	Power Engineering & Construction	Eng & Constr Gas Util MW only	UTMCONGAS	S64	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Human Resources	Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments. Supervises contract negotiations and relations with labor	*Number of Employees Ratio*	DGHR	Human Resources	HR Svcs Gvrnce	DGOVEMPHRS	DG2	39.06	26.83	15.18	6.46	0.71	1.56	-	89.80
			DHRE	Human Resources	HR Services Enterprise DE	DENTEMPHRS	D04	39.06	26.83	15.18	6.46	0.71	1.56	-	89.80
			UTHR	Human Resources	HR Services Utility	UTIEMPHRS	S38	39.76	27.33	15.45	6.58	0.73	1.59	-	91.44
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Supply Chain - Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.	Procurement of materials and contract services and vendor payment processing:	*Procurement Spending Ratio*	DUSC	Materials Management	Matls Mgmt Sply Chn Util DE	DUTIPROSPC	D19	37.82	22.25	16.71	11.09	2.57	4.14	0.03	94.61
			DESC	Materials Management	Matls Mgmt Sply Chain Ent DE	DENTPROSPC	D08	37.29	22.04	16.48	10.93	2.54	4.08	0.04	93.40
			UPPD	Materials Management	MW ELEC/GAS DELIVRY STOREROOM	UTBROPSMM	S72	-	-	-	-	7.13	76.95	-	84.08
	Management of materials and supplies inventory.	*Inventory Ratio*	UTIN	Materials	Matls Mgmt Inventory Util	UTIINVSPC	S20	17.21	26.44	26.72	15.67	0.14	13.82	-	100.00
								-	-	-	-	-	-	-	-
Facilities	Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.	*Square Footage Ratio*	GORE	Facilities	RE Facility Svcs CLT GO	CLTSQFFAC	S27	55.94	38.44	0.33	5.03	-	-	-	99.74
			CNRE	Facilities	RE Fac Svcs - Cincinnati	CINSQFFAC	S50	25.56	17.55	-	8.82	-	11.54	-	63.47
			PLRE	Facilities	RE Fac Svcs - Plainfield	PLDSQFFAC	S51	10.09	6.94	0.78	80.44	0.31	-	-	98.56
			MWRE	Facilities	RE Facility Services MW Utility	UTMSQFFAC	S71	-	-	-	59.10	4.21	21.03	-	84.34
			DERE	Facilities	RE Facility Services Ent DE	DENT3FFFAC	D39	41.62	28.61	15.62	5.37	0.02	0.32	-	91.56
Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	*Three Factor Formula*	DGAC	Accounting	Accounting Gvrnce	DGOV3FFACT	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			DGVP	Accounting	VSP - Governance DE	DGOV3FFVSP	DG3	36.94	24.65	17.42	11.10	1.18	3.59	0.02	94.90
			PGVP	Accounting	VSP - Governance	PRGV3FFVSP	PG3	-	58.46	41.54	-	-	-	-	100.00
			DEAC	Accounting	Accounting Svcs Ent DE	DENT3FFACT	D03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			UTAC	Accounting	Acctg Svcs Utility	UTI3FFACT	S09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
			UMAC	Accounting	Acctg Svcs Util MW FE&G only	UTM3FFACT	S53	-	-	-	62.68	6.76	19.55	-	88.99
			DDEP	Accounting	DEBS Depreciation DE	DENT3FFDEP	D49	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			PRDP	Accounting	SvcCo Depreciation PE	PRE3FFDEPR	P49	-	58.46	41.54	-	-	-	-	100.00
			DGDC	Accounting	Governance CTA Depreciation DE	DGOV3FDEPP	DG4	36.94	24.65	17.42	11.10	1.18	3.59	0.02	94.90
			DCTG	Accounting	CTA Governance DE	DGOV3FFCTA	DG3	36.94	24.65	17.42	11.10	1.18	3.59	0.02	94.90
			PNYG	Accounting	Piedmont CTA Gov	GOV3FFCTAP	DG7	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			PNGG	Accounting	Piedmont CTA Gov - Gas Only	GOV3FCTAPG	DG6	-	-	-	-	-	-	-	-
			PUDC	Accounting	Governance CTA Depreciation PE	PRV3FFDEPP	PG4	-	58.46	41.54	-	-	-	-	100.00
			GSAC	Accounting	Accounting Gas Only	UTI3FFGACT	GD3	-	-	-	-	-	-	-	-
		Generating Unit MW Capability Ratio (MDC)	DPNL	Accounting	Duke Progress CTA Nuclear	DGOV3FFDPN	CG3	67.00	33.00	-	-	-	-	-	100.00
	Rate of Return - Allocates the Service Company's portion of the utilities chargeback for affiliate use of space.	*Three Factor Formula*	DURR	Facilities Rate of Return Allocation	Facilities ROR Gvrnce DE	DGOVEMPROR	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
Power Planning and Operations - Coordinates the planning, management and operation of Duke Energy Corporation's electric power systems including additions and retirements to Duke Energy Corporation's electric generation, transmission and distribution systems.	Generation planning:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUGE	Power Planning and Ops	Pwr Plng&Ops Gen Plng Util ND	DUTIPKLGPL	D21	37.79	28.24	19.81	12.47	1.69	-	-	100.00
	Transmission planning:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util ND	DUTIPKLETR	D32	37.91	22.77	19.51	11.74	1.30	6.77	-	100.00
	Distribution planning:	Weighted Avg of the *Circ Miles of ED Lines Ratio* and the *Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util ND	DUTICMIEDL	D41	38.57	24.18	17.95	11.56	1.20	6.54	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-

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2019 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Comm Trans-Elec	Total Electric Utilities
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	*Sales Ratio*	UTGD	Power Planning and	Pwr Plng&Ops Gen Dsptch Util	UTISALGDP	S42	27.00	23.12	26.58	20.15	3.15	-	-	100.00
								-	-	-	-	-	-	-	-
	Transmission Operations:	Weighted Average of the *Circ Miles of Elec Transm Lines*	UTTO	Power Planning and	Pwr Plng&Ops Trans Ops Util	UTICMICTR	S31	39.39	21.15	17.47	14.17	0.82	7.00	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Distribution Operations:	Weighted Avg of *Circ Miles of ED Lines Ratio* & *Elec Peak Load Ratio*	UTDO	Power Planning and	Pwr Plng & Ops Dist Ops Util	UTICMICDL	S22	38.57	24.18	17.95	11.56	1.20	6.54	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.	*Generating Unit MW Capability /MDC Ratio*						-	-	-	-	-	-	-	-
			REPO	Power Planning and Ops	Pwr Plng & Ops Pwr Ops Reg	REGCAPPOP	S28	29.28	24.15	24.36	19.32	2.89	-	-	100.00
			RCLO	Power Planning and Ops	Reg Coal - All Juris (DEBS)	RCLCAPPOP	D99	35.97	18.38	16.60	25.94	3.11	-	-	100.00
			RCTO	Power Planning and Ops	Reg CT/CC- All Juris (DEBS)	RCTCAPPOP	S98	22.15	30.30	32.65	12.26	2.64	-	-	100.00
			RMWO	Power Planning and Ops	Reg Coal/CT - Midwest (DEBS)	REGMCAPOP	S99	-	-	-	87.02	12.98	-	-	100.00
Public Affairs	Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction lithography, photography and video services.	*Three Factor Formula*	DGPA	Public Affairs	Pub Affrs Grnce	DGOV3FFPAF	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			DGPP	Public Affairs	Public Policy Grnce	DGOV3FFPPO	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			DEPA	Public Affairs	Public Affairs Services Ent DE	DENT3FFPAF	D03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
	Utility Specific Activities	Weighted Average of *# of Customers Ratio* and *# of Employees Ratio*	UTPA	Public Affairs	Public Affairs Services Utilit	UTICUSPAF	S24	33.93	22.17	17.47	7.72	1.13	4.65	-	87.07
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Legal	Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.	*Three Factor Formula*	DLEE	Legal	Legal Governance	DGOV3FFLEG	CG1	64.11	-	-	19.03	2.02	6.14	0.03	91.33
			ENLE	Legal	Legal Governance	GOV3FFLEG	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			PGLG	Legal	Legal Governance PE	PRGV3FFLEG	PG1	-	58.46	41.54	-	-	-	-	100.00
			UTLE	Legal	Legal Services Utility	UTI3FFLEG	S09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Rates	Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers' usage.	*Sales Ratio*	UTRA	Rates	Rates Utility	UTISALRAT	S44	28.87	20.71	13.58	10.61	1.34	6.66	-	81.77
			UCRA	Rates	Rates Svcs Util DEO DEK only	UTOSALRAT	S55	-	-	-	-	9.36	52.42	-	61.78
			UMRA	Rates	Rates DEO & DEK Reg	UTMSALRAT	S86	-	-	-	-	7.92	39.48	-	47.40
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Finance	Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.	*Three Factor Formula*	DGFI	Finance	Financial Svcs Grnce	DGOV3FFFIN	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			DEFI	Finance	Financial Svcs DE	DENT3FFFIN	D03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			UTFI	Finance	Financial Services Utility	UTI3FFFIN	S09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
			UMFI	Finance	Financial Svc Util MW FEG only	UTM3FFFIN	S53	-	-	-	62.68	6.76	19.55	-	88.99
								-	-	-	-	-	-	-	-
Rights of Way - Purchases, surveys, records, and sells real estate interests for Client Companies.	Services related to electric distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*						-	-	-	-	-	-	-	-
			DURD	Rights of Way	Right of Way ED Sys Util ND	DUTICMIRWD	D87	39.27	25.58	16.38	11.38	1.10	6.29	-	100.00
								-	-	-	-	-	-	-	-
	Services related to electric generation system:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DURG	Rights of Way	Right of Way Gen Sys Util ND	DUTIPKLRWG	D88	37.79	28.24	19.81	12.47	1.69	-	-	100.00
								-	-	-	-	-	-	-	-
	Services related to electric transmission system:	*Circuit Miles of Electric Transm Lines Ratio*						-	-	-	-	-	-	-	-
			DURW	Rights of Way	Right of Way ET Sys Util ND	DUTICMIROW	D45	40.89	19.53	15.43	16.60	0.33	7.22	-	100.00
								-	-	-	-	-	-	-	-
Internal Auditing	Reviews internal controls and procedures to ensure that assets are safeguarded & that transactions are properly authorized & recorded.	*Three Factor Formula*	DGIA	Internal Auditing	Internal Audit Grnce	DGOV3FFIAU	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
			DUIA	Internal Auditing	Intrnl Audit Svcs Utility DE	DUTI3FFIAU	D09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Three Factor Formula*	DGEA	Environmental, Health and Safety	Envir Affrs Grnce	DGOV3FFENV	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
			ENEA	Environmental, Health and Safety	Enviro Affairs Svcs Ent	ENT3FFENV	S46	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Utility Specific Activities	*Sales Ratio*	UTEA	Environmental,	Enviro Affairs Svcs Utility	UTISALENV	S47	28.87	20.71	13.58	10.61	1.34	6.66	-	81.77
								-	-	-	-	-	-	-	-

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COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	Sx Ctl	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Comm Trans-Elec	Total Electric Utilities
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	UTFU	Fuels	Fuels Utility	UTIS4LRUE	S48	27.00	23.12	26.58	20.15	3.15	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Investor Relations	Communicates to investors and the community, performs transfer agent and shareholder record keeping functions, administers stock plans, and performs stock-related regulatory reporting.	*Three Factor Formula*	DGIR	Investor Relations	Investor Rel Grnce	DGOV3FRNV	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
Planning	Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.	*Three Factor Formula*	DGPS	Planning	Planning Svcs Grnce	DGOV3FRPLN	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			DGCD	Planning	Corp Dvlpmnt Grnce	DGOV3FRCDO	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
			DEPS	Planning	Planning Svcs Enterprise DE	DENT3FRPLN	D03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
								-	-	-	-	-	-	-	-
			DUPS	Planning	Planning Svcs Utility DE	DUT3FRPLN	D09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
Executive	Provides general administrative and executive management services.	*Three Factor Formula*	DGEX	Executive	Exec Governance	DGOV3FREXC	DG1	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			ENEX	Executive	Exec Services Enterprise	ENT3FREXC	S03	34.84	23.26	16.44	10.48	1.11	3.40	0.02	89.55
			UTEX	Executive	Exec Services Utility	UT13FREXC	S09	35.84	23.91	16.92	10.81	1.14	3.50	0.02	92.14
			UMEX	Executive	Executive Svc Util MW REGonly	UTM3FREXC	S53	-	-	-	62.68	6.76	19.55	-	88.99
			UOEX	Executive	Exec Svcs Utility DEO DEK only	UT03FREXC	S56	-	-	-	-	18.39	52.22	-	70.61
			DGSC	Executive	Stock Comp Legacy DE	GOV3FRSTK	CG1	64.11	-	-	19.03	2.02	6.14	0.03	91.33
			PSTK	Executive	Stock Comp Legacy PGN	PRG3FRSTK	PG1	-	58.46	41.54	-	-	-	-	100.00
Interest	Allocates Interest		DEAI	Interest	Accts g Interest Svc Enterprise	DENTINTACT	D52	33.71	18.68	12.31	15.11	2.77	8.64	0.05	91.27

2019 SERVICE COMPANY COST ALLOCATION DETAILS
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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Information Systems	Development and support of mainframe computer software applications.	*Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second*	ENMF	Information Systems	Mainframe Svcs Ent	ENTCPUMFR	S05	-	1.48	6.37	-	7.85	-	-	100.00
			PRMF	Information Systems	Mainframe Svcs Ent PE	PRECPUMFR	P05	-	-	-	-	-	-	-	100.00
			DEMF	Information Systems	Mainframe Svcs Ent DUK	DENTCPUMFR	D05	5.07	1.01	4.37	-	10.45	-	-	100.00
			PUMF	Information Systems	Mainframe Svcs Utility PE	PRUCPUMFR	P11	-	-	-	-	-	-	-	100.00
	Procurement and support of personal computers and related network and software applications.	*No. of Personal Computer Workstations Ratio*	ENWS	Information Systems	Worksta Svcs Enterprise	ENTWKSWKS	S06	-	0.31	0.63	-	0.94	3.29	1.32	100.00
			PRWS	Information Systems	Worksta Svcs Enterprise PE	PREWKSWKS	P06	-	-	-	-	-	-	1.23	100.00
			DWSE	Information Systems	Worksta Svcs Enterprise DUK	DENTWKSWKS	D06	4.26	0.16	0.32	-	4.74	1.67	1.21	100.00
			PUWS	Information Systems	Worksta Svcs Utility PE	PRUWKSWKS	P12	-	-	-	-	-	-	1.22	100.00
	Development and support of distributed computer software applications (e.g., servers).	*Number of Info Systems Servers Ratio*	ENSS	Information Systems	Server Svcs Enterprise	ENTSYSSVR	S07	-	1.62	6.19	-	7.81	0.44	1.80	100.00
			PRSS	Information Systems	Server Svcs Enterprise PE	PRESYSSVR	P07	-	-	-	-	-	-	1.53	100.00
			DESS	Information Systems	Server Svcs Enterprise DUK	DENTSYSSVR	D07	7.22	0.90	3.45	-	11.57	0.24	1.58	100.00
			UTSS	Information Systems	Server Svcs Utility	UTISYSSVR	S13	7.27	0.90	3.47	-	11.64	-	1.02	100.00
			PUSS	Information Systems	Server Svcs Utility PE	PRUSYSSVR	P13	-	-	-	-	-	-	1.53	100.00
	Installation and operation of communications systems.	*Number of Employees Ratio*	ENTS	Information Systems	Telecom Svcs Enterprise	ENTEMPTEL	S33	-	0.53	0.90	-	1.43	3.59	1.39	100.00
			PRTS	Information Systems	Telecom Svcs Enterprise PE	PREEMPTEL	P33	-	-	-	-	-	-	1.24	100.00
			DETS	Information Systems	Telecom Svcs Enterprise DUK	DENTEMPTEL	D33	7.68	0.27	0.45	-	8.40	1.80	1.22	100.00
			DUTS	Information Systems	Telecom Svcs Utility	DUTIEMPTEL	D34	7.82	0.27	0.46	-	8.55	-	1.26	100.00
			UTTS	Information Systems	Telecom Svcs Utility	UTIEMPTEL	S34	-	0.55	0.94	-	1.49	-	1.44	100.00
			PTSU	Information Systems	Telecom Svcs Utility PE	PRUEMPTEL	P34	-	-	-	-	-	-	1.24	100.00
			ENHD	Information Systems	Helpdesk Services	ENTEMPHLP	S33	-	0.53	0.90	-	1.43	3.59	1.39	100.00
			DEHD	Information Systems	Helpdesk Services DUK	DENTEMPHLP	D33	7.68	0.27	0.45	-	8.40	1.80	1.22	100.00
			PRHD	Information Systems	helpdesk Services PE	PREEMPHLP	P33	-	-	-	-	-	-	1.24	100.00
	Information systems management and support services.	*No. of Personal Computer Workstations Ratio*	ENMA	Information Systems	ITS Mgt & Apps Svcs Ent	ENT3FFITM	S35	7.75	0.29	0.58	-	8.62	3.03	1.22	100.00
			DEMA	Information Systems	ITS Mgt & Apps Svcs Ent DE	DENT3FFITM	D35	4.26	0.16	0.32	-	4.74	1.67	1.21	100.00
			PRMA	Information Systems	ITS Mgt & Apps Svcs Ent PE	PREJFFITM	P35	-	-	-	-	-	-	1.23	100.00
			UTMA	Information Systems	ITS Mgt & Apps Utility	UTI3FFITM	S36	-	0.32	0.65	-	0.97	-	1.37	100.00
			DELH	Information Systems	Duke Energy Lighthouse	DUWKSITM	D11	4.33	0.16	0.32	-	4.81	-	1.24	100.00
			DUMA	Information Systems	ITS Mgt & Apps Svcs Util DE	DUT3FFITM	D36	4.26	0.16	0.32	-	4.74	1.67	1.21	100.00
								-	-	-	-	-	-	-	-
Meters	Procures, tests and maintains meters.	*Number of Customers Ratio*						-	-	-	-	-	-	-	-
			DEMS	Meters	Meter Svcs Utility DE	DUTICUSMTR	D14	11.56	1.07	4.66	-	17.29	-	-	100.00
			UMMS	Meters	Meter Svcs Util MWonly Elec/Gas	UTMCUSMTR	S60	-	4.48	19.55	-	24.03	-	-	100.00
			UEMS	Meters	Meter Svcs Util MW Elec	UTECUSMTR	S58	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Transportation	Procures and maintains vehicles and equipment.	*Number of Employees Ratio*	DUVE	Transportation	Transp Vehicles Utility DE	DUTIEMPVEH	D10	7.83	0.15	0.58	-	8.56	-	-	100.00
			UMVE	Transportation	Transp Vehicles Util MW only	UTMEMPVEH	S65	-	1.53	6.05	-	7.58	-	-	100.00
								-	-	-	-	-	-	-	-
	Procures and maintains aircraft and equipment.	*Three Factor Formula*	DGAV	Transportation	Transp Aviation Gurnee	DGOV3FFAVI	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
			DEAV	Transportation	Transp Aviation Svcs Ent DE	DENT3FFAVI	D03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission system	*Circuit Miles of Electric Transm Lines Ratio*	UTTR	Electric System	ESS Elec Tran Utility	UTICMIETR	S15	-	-	-	-	-	-	-	100.00
			UMTR	Electric System Maintenance	ESS Elec Tran Utility - MW	UTICMIEMW	S96	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Services related to distribution system	*Circuit Miles of Electric Dist. Lines Ratio*	UTDI	Electric System	ESS Elec Dist Utility	UTICMIEDT	S16	-	-	-	-	-	-	-	100.00
			UMDI	Electric System Maintenance	ESS Elec Dist Utility MW only	UTMCMIEDT	S57	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*						-	-	-	-	-	-	-	-
			PUSD	Marketing and	M&CR SALES & Demand Util PE	PRUTSALMCR	P17	-	-	-	-	-	-	-	100.00
			NET	Marketing and Customer Relations	Customer Strategy P&S	UTISALNET	S75	-	-	-	-	-	-	-	100.00
			STD	Marketing and Customer Relations	Standard Services	UTISALSTD	S17	-	2.06	8.97	-	11.03	-	-	100.00
			MSST	Marketing and Customer Relations	Mkt Sol - SrvCo Duke Standard	UTMSOLSTD	D98	-	-	-	-	-	-	-	100.00
			UMSD	Marketing and Customer Relations	M&CR Standard Prod Util MWonly	UTMSALNET	S68	-	4.48	19.55	-	24.03	-	-	100.00
			UMNT	Marketing and Customer Relations	M&CR Net Product Util MW only	UTMSALSTD	S68	-	4.48	19.55	-	24.03	-	-	100.00

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Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*	UESD	Marketing and Customer Relations	M&CR Sls&Dmnd Util MW Elec only	UTMSALMCR	S66	-	-	-	-	-	-	-	100.00
			UGSD	Marketing and Customer Relations	M&CRSales&Demand Util MWGas only	UTGSALMCR	S67	-	18.66	81.34	-	100.00	-	-	100.00
			DTNT	Marketing and Customer Relations	M&CR Elec Only Util DE	DUTDLSMCR	D75	-	-	-	-	-	-	-	100.00
			UTNT	Marketing and Customer Relations	M&CRSales&Demand Util MWGas only	UTSANET	S75	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	UTMR	Marketing and Customer Relations	M&CR Mtr Rdg&Pmt Proc Util	UTDLSPMT	S37	-	2.06	8.97	-	11.03	-	-	100.00
			DUMR	Marketing and Customer Relations	M&CR Customers Util ND	DUTDLSPMT	D37	11.56	1.07	4.66	-	17.29	-	-	100.00
			DUMS	Marketing and Customer Relations	M&CR Sol Services Utilities Sold	DUTDLSPAY	D95	-	-	-	-	-	-	-	100.00
			UMMR	Marketing and Customer Relations	M&CR MtrRdg&PmtPrc Util MWonly	UTMDLSPMT	S60	-	4.48	19.55	-	24.03	-	-	100.00
			UDMR	Marketing and Customer Relations	M&CR MtrRdg&PmtPrc DEO DEK only	UTDDLSPMT	S59	-	7.14	31.13	-	38.27	-	-	100.00
			DCTH	Marketing and Customer Relations	M&CR Customers Util ND	DDDVDLSCTA	D65	-	1.21	5.27	-	6.48	-	-	100.00
	Customer services including the operation of call center.	*Number of Customers Ratio*	UEMR	Marketing and Customer Relations	M&CR MtrRdg&PmtPrc Util	UTEDLSPMT	S58	-	-	-	-	-	-	-	100.00
			UMPD	Marketing and Customer Relations	M&CR Util MW PD	UTMDLSMPD	S69	-	4.48	19.55	-	24.03	-	-	100.00
			DCIS	Marketing and Customer Relations	M&CR Cust Info Sys_Util	DUTDLSSYS	T05	-	1.21	5.27	-	6.48	-	-	100.00
			UWPD	Marketing and Customer Relations	M&CR PD DEO DEK EIG	UTMDLSWPD	S70	-	7.14	31.13	-	38.27	-	-	100.00
	Costs associated with Smart Grid activities	*Number of Customers Ratio*	USGA	Marketing and Customer Relations	M&CR Smart Grid All EIG	UTDLSSSG	S76	-	2.06	8.97	-	11.03	-	-	100.00
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only	UTEDLSSG	S77	-	-	-	-	-	-	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE EIG	DUTDLSSG	D89	-	1.21	5.27	-	6.48	-	-	100.00
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only	DUTEDLSSG	D93	-	-	-	-	-	-	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES O&M	UTDLSSES	S84	-	2.06	8.97	-	11.03	-	-	100.00
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC EIG	PUTDLSSG	P91	-	-	-	-	-	-	-	100.00
			USGA	Marketing and Customer Relations	M&CR Smart Grid Util Capital	UTDLSSG	S80	-	2.06	8.97	-	11.03	-	-	100.00
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only Capital	UTEDLSSG	S81	-	-	-	-	-	-	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE EIG - Capital	DUTDLSSG	D90	-	1.21	5.27	-	6.48	-	-	100.00
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only - Capital	DUTEDLSSG	D94	-	-	-	-	-	-	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES Cap	UTDLSSES	S85	-	2.06	8.97	-	11.03	-	-	100.00
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC EIG - Capital	PUTDLSSG	P92	-	-	-	-	-	-	-	100.00
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE EIG	DUTDLSGS	T01	-	1.21	5.27	-	6.48	-	-	100.00
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE EIG - Capital	DUTDLSGS	T02	-	1.21	5.27	-	6.48	-	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric	DUTEDLSGS	T03	-	-	-	-	-	-	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric - Capital	DUTEDLSGS	T04	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Electric Transmission & Distribution Engineering & Construction - Designs and monitors construction of electric transmission and distribution lines and substations. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.	Transmission engineering and construction.	*(Electric Transmission Plant's) Construction - Expenditures Ratio*	UTET	Electric Transmission	Eng & Constr ET Utility	UTTCONETR	S18	-	-	-	-	-	-	-	100.00
			UET	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ET Util MW only	UTMCONETR	S62	-	-	-	-	-	-	-	100.00
	Distribution engineering and construction.	*(Electric Distribution Plant's) Construction - Expenditures Ratio*	UTED	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ED Utility	UTTCONEDT	S30	-	-	-	-	-	-	-	100.00
			UED		Eng & Constr ED Util MW only	UTMCONEDT	S61	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
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Power Engineering & Construction	Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	*(Electric Production Plant's) Construction - Expenditures Ratio*	UTEC	Power Engineering & Construction	Eng & Constr Pwr Prod Util	UTECONPWR	S25	-	-	-	-	-	-	-	100.00
			UBEC	Power Engineering & Construction	Engg&Constr Pwr Prod Util MWonly	UTMCONPWR	S63	-	-	-	-	-	-	-	100.00
			UBEG	Power Engineering & Construction	Eng & Constr Gas Util MW only	UTMCONGAS	S64	82.81	4.84	12.35	-	100.00	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Human Resources	Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments.. Supervises contract negotiations and relations with labor	*Number of Employees Ratio*	DGHR	Human Resources	HR Svcs Gernce	DGOVEMPHRS	DG2	7.69	0.14	0.57	-	8.40	1.80	-	100.00
			DHRE	Human Resources	HR Services Enterprise DE	DENTEMPHRS	D04	7.69	0.14	0.57	-	8.40	1.80	-	100.00
			UTHR	Human Resources	HR Services Utility	UTIEMPHRS	S38	7.83	0.15	0.58	-	8.56	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Supply Chain - Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.	Procurement of materials and contract services and vendor payment processing:	*Procurement Spending Ratio*	DUSC	Materials Management	Matls Mgmt Sply Chn Util DE	DUTPROSPC	D19	3.29	0.53	1.21	-	5.03	-	0.38	100.00
			DESC	Materials Management	Matls Mgmt Sply Chain Ent DE	DENTPROSPC	D08	3.25	0.52	1.19	-	4.96	1.27	0.37	100.00
			UPPD	Materials Management	MW ELEC/GAS DELIVRY STOREROOM	UTIPROSMM	S72	-	4.04	11.88	-	15.92	-	-	100.00
	Management of materials and supplies inventory.	*Inventory Ratio*	UTIN	Materials Management	Matls Mgmt Inventory Util	UTIINVSPC	S20	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Facilities	Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.	*Square Footage Ratio*	GCRE	Facilities	RE Facility Svcs CLT GO	CLTSQFFAC	S27	-	-	-	-	-	0.26	-	100.00
			CNRE	Facilities	RE Fac Svcs - Cincinnati	CINSQFFAC	S50	6.51	-	4.23	-	10.74	25.79	-	100.00
			PLRE	Facilities	RE Fac Svcs - Plainfield	PLDSQFFAC	S51	-	0.06	-	-	0.06	1.38	-	100.00
			MVRE	Facilities	RE Facility Services MW Utility	UTMSQFFAC	S71	-	2.95	12.71	-	15.66	-	-	100.00
			DERE	Facilities	RE Facility Services Ent DE	DENTSRFFAC	D39	7.17	-	0.12	0.36	7.65	0.79	-	100.00
Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	*Three Factor Formula*	DGAC	Accounting	Accounting Gvrnce	DGOVSRFACT	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DGVP	Accounting	VSP - Governance DE	DGOVSRFVSP	DG3	-	0.39	1.70	0.02	2.11	2.92	0.07	100.00
			PGVP	Accounting	VSP - Governance	PRGVSRFVSP	PG3	-	-	-	-	-	-	-	100.00
			DEAC	Accounting	Accounting Svcs Ent DE	DENTSRFACT	D03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			UTAC	Accounting	Acctg Svcs Utility	UTISRFACT	S09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
			UMAC	Accounting	Acctg Svcs Util MW FEB Gonly	UTMSRFACT	S53	-	2.24	8.77	-	11.01	-	-	100.00
			DDEP	Accounting	DEBS Depreciation DE	DENTSRDEP	D49	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			PRDP	Accounting	SvcCo Depreciation PE	PRESRDEPR	P49	-	-	-	-	-	-	-	100.00
			DGOC	Accounting	Governance CTA Depreciation DE	DGOVSRDEPP	DG4	-	0.39	1.70	0.02	2.11	2.92	0.07	100.00
			DCTG	Accounting	CT A Governance DE	DGOVSRCTA	DG3	-	0.39	1.70	0.02	2.11	2.92	0.07	100.00
			PNVG	Accounting	Piedmont CT A Gov	GOVSRCTAP	DG7	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			PNGS	Accounting	Piedmont CT A Gov - Gas Only	GOVSRCTAPG	DG6	74.56	4.80	20.64	-	100.00	-	-	100.00
			PUDC	Accounting	Governance CTA Depreciation PE	PRVSRDEPP	PG4	-	-	-	-	-	-	-	100.00
			GSAC	Accounting	Accounting Gas Only	UTESRGACT	G03	74.55	4.80	20.65	-	100.00	-	-	100.00
		Generating Unit MW Capability Ratio (NDC)	DRAL	Accounting	Duke Progress CT A Nuclear	DGOVSRDPN	CE3	-	-	-	-	-	-	-	100.00
	Rate of Return - Allocates the Service Company's portion of the utilities chargeback for affiliate use of space.	*Three Factor Formula*	DURR	Facilities Rate of Return Allocation	Facilities ROR Gvrnce DE	DGOVEMPROR	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
Power Planning and Operations - Coordinates the planning, management and operation of Duke Energy Corporation's electric power systems including additions and retirements to Duke Energy Corporation's electric generation.	Generation planning:	*Elec Peak Load Ratio*	DUGE	Power Planning and Ops	Pwr Plng&Ops Gen Plng Util ND	DUTPNLGR1	D21	-	-	-	-	-	-	-	-
	Transmission planning:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util ND	DUTPNLETR	D32	-	-	-	-	-	-	-	100.00
	Distribution planning:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Elec Peak Load Ratio	DUDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util ND	DUTIOMEEL	D41	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-

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COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	Sr Cd	Total PNG	Total DEK Gas	Total DEO Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	*Sales Ratio*	UTGD	Power Planning and	Pwr Plng&Ops Gen Dsptch Util	UTSALGDP	S42	-	-	-	-	-	-	-	100.00
	Transmission Operations:	Weighted Average of the *Circ Miles of Elec Transm Lines*	UTTO	Power Planning and	Pwr Plng&Ops Trans Ops Util	UTTOMOTR	S31	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Distribution Operations:	*Weighted Avg of Circ Miles of ED Lines Ratio & Elec Peak Load Ratio*	UTDO	Power Planning and	Pwr Plng &. Ops Dist Ops Util	UTDOMTOD	S22	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
		Generating Unit MW Capability /MDC Ratio						-	-	-	-	-	-	-	-
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.		REPO	Power Planning and Ops	Pwr Plng &. Ops Pwr Ops Reg	REGCAPPOP	S28	-	-	-	-	-	-	-	100.00
			RGLO	Power Planning and Ops	Reg Coal - All Juris (DEBS)	RGLCAPPOP	D99	-	-	-	-	-	-	-	100.00
			RCTO	Power Planning and Ops	Reg CT/CC - All Juris (DEBS)	RCTCAPPOP	S98	-	-	-	-	-	-	-	100.00
			RMWO	Power Planning and Ops	Reg Coal/CT - Midwest (DEBS)	REGMOAPOP	S99	-	-	-	-	-	-	-	100.00
Public Affairs	Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction, lithography, photography and video services.	*Three Factor Formula*	DGPA	Public Affairs	Pub Affs Gvrnce	DGOV3FPAF	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DGPP	Public Affairs	Public Policy/Gvrnce	DGOV3FPPO	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DBPA	Public Affairs	Public Affairs Services Ent DE	DENT3FPAF	D03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
	Utility Specific Activities	Weighted Average of *# of Customers Ratio* and *# of Employees Ratio*	UTPA	Public Affairs	Public Affairs Services Utilit	UTPOLSPAF	S24	9.70	0.61	2.62	-	12.93	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Legal	Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.	*Three Factor Formula*	DLEE	Legal	Legal Governance	DGOV3FLEG	DG1	-	0.67	2.88	0.03	3.58	4.97	0.12	100.00
			ENLE	Legal	Legal Governance	GOV3FLEG	D81	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			PGLG	Legal	Legal Governance PE	PROV3FLEG	P81	-	-	-	-	-	-	-	100.00
			UTLE	Legal	Legal Services Utility	UTI3FLEG	S09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Rates	Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers' usage.	*Sales Ratio*	UTRA	Rates	Rates Utility	UTSALRAT	S44	9.35	1.35	7.53	-	18.23	-	-	100.00
			UORA	Rates	Rates Svcs Util DEO DEK only	UTOSALRAT	S55	-	6.55	31.67	-	38.22	-	-	100.00
			UMRA	Rates	Rates DEO &. DEK Reg	UTMSALRAT	S86	-	8.00	44.60	-	52.60	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Finance	Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.	*Three Factor Formula*	DGFI	Finance	Financial Svcs Gvrnce	DGOV3FFIN	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DEFI	Finance	Financial Svcs DE	DENT3FFIN	D03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			UTFI	Finance	Financial Services Utility	UT3FFIN	S09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
			UMFI	Finance	Financial Svc Util MW REG only	UTMGFFIN	S53	-	2.24	8.77	-	11.01	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Rights of Way - Purchases, surveys, records, and sells real estate interests for Client Companies.	Services related to electric distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	DURD	Rights of Way	Right of Way ED Sys Util ND	DUTIOMRWD	D87	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Services related to electric generation system:	*Elec Peak Load Ratio*	DURG	Rights of Way	Right of Way Gen Sys Util ND	DUTIPKLRWG	D88	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Services related to electric transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	DURW	Rights of Way	Right of Way ET Sys Util ND	DUTIOMROW	D45	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Internal Auditing	Reviews internal controls and procedures to ensure that assets are safeguarded & that transactions are properly authorized & recorded.	*Three Factor Formula*	DGIA	Internal Auditing	Internal Audit Gvrnce	DGOV3FIAU	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DUIA	Internal Auditing	Intrnl Audit Svcs Utility/DE	DUTBFIAU	D09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
								-	-	-	-	-	-	-	-
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Three Factor Formula*	DGEA	Environmental, Health and Safety	Envir Affs Gvrnce	DGOV3FENV	DG1	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
			ENEA	Environmental, Health and Safety	Enviro Affairs Svcs Ent	ENT3FENV	S46	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Utility Specific Activities	*Sales Ratio*	UTEA	Environmental,	Enviro Affairs Svcs Utility	UTSALENV	S47	9.35	1.35	7.53	-	18.23	-	-	100.00
								-	-	-	-	-	-	-	-

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2019 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	UTFU	Fuels	Fuels Utility	UTISALFUE	548	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Investor Relations	Communicates to investors and the community, performs transfer agent and shareholder record keeping functions, administers stock plans, and performs stock-related regulatory reporting.	*Three Factor Formula*	DGIR	Investor Relations	Investor Rel Gvrnce	DGOV3FFINV	DGI	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
Planning	Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.	*Three Factor Formula*	DGPS	Planning	Planning Svcs Gvrnce	DGOV3FFPLN	DGI	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			DGCD	Planning	Corp Dvlpmnt Gvrnce	DGOV3FFCDO	DGI	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
			DEPS	Planning	Planning Svcs Enterprise DE	DENT3FFPLN	D03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
								-	-	-	-	-	-	-	-
			DUPS	Planning	Planning Svcs Utility DE	DUT3FFPLN	D09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
Executive	Provides general administrative and executive management services.	*Three Factor Formula*	DGEX	Executive	Exec Governance	DGOV3FFEXC	DGI	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			ENEX	Executive	Exec Services Enterprise	ENT3FFEXC	S03	5.63	0.37	1.61	0.02	7.63	2.76	0.06	100.00
			UTEX	Executive	Exec Services Utility	UT3FFEXC	S09	5.80	0.38	1.66	0.02	7.86	-	-	100.00
			UMEX	Executive	Executive Svc Util MW FEGonly	UTMBFFEXC	S53	-	2.24	8.77	-	11.01	-	-	100.00
			UOEX	Executive	Exec Svcs Utility DEO DEK only	UTOBFFEXC	S56	-	6.09	23.30	-	29.39	-	-	100.00
			DOSC	Executive	Stock Comp Legacy DE	GOV3FFSTK	CGI	-	0.67	2.88	0.03	3.58	4.97	0.12	100.00
			PSTK	Executive	Stock Comp Legacy PGN	PRGV3FFSTK	PGI	-	-	-	-	-	-	-	100.00
Interest	Allocates Interest							-	-	-	-	-	-	-	-
			DEAI	Interest	Accts Interest Svc Enterprise	DENTINTACT	D52	4.43	0.45	2.35	0.10	7.33	1.37	0.03	100.00

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I. GUIDELINES AND PROCEDURE FOR CHARGING AFFILIATES FOR COSTS ORIGINATING WITH DEC/DEP/PIEDMONT

On occasion, DEC/DEP/Piedmont's employees may be requested to provide support, subject to availability, to Affiliates and Nonpublic Utility Operations. DEC/DEP/Piedmont's management is responsible for ensuring that use of all company resources to support Affiliate work is properly charged to the Affiliate/Nonpublic Utility Operation. Rules regarding affiliate agreements between DEC/DEP/Piedmont and any Affiliate/Nonpublic Utility Operation are described in Section E. *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates* incorporated in this CAM. DEC/DEP/Piedmont will charge the Affiliate/Nonpublic Utility Operation the higher of fully distributed cost or market value. Charging the Affiliate/Nonpublic Utility Operation either market or fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. DEC/DEP/Piedmont's management is accountable for the review and approval of all charges from the utility in support of Affiliate/ Nonpublic Utility Operation work. An Affiliate Rules and Transactions CBT (emphasis on DEC/DEP/Piedmont) is available on the employee portal.

Costs covered by the utility affiliate loader are handled by utility departmental allocations and a change to the Service Company allocation basis. These steps eliminate the need for a utility affiliate loader between DEC and DEP, because the costs of the utility affiliate loader are now addressed in a simplified fashion between the two Companies. The utility affiliate loader still applies for all labor charged outside of DEC and DEP to their affiliates.

The following procedure addresses employees' and management's responsibilities.

A. General Guidelines

1. Hours worked by DEC/DEP/Piedmont employees in direct support of an Affiliate/ Nonpublic Utility Operation are charged directly to the Affiliate.

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2. First-line supervisors should review and approve, when appropriate, source documentation resulting in a charge by DEC/DEP/Piedmont to an Affiliate/ Nonpublic Utility Operation (timesheets, employee expenses, etc.).
3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to an Affiliate/ Nonpublic Utility Operation.
4. Transactions originating with DEC/DEP/Piedmont and charged to an Affiliate typically require the completion and approval of a Service Request form. The process and eForm can be found on the Portal under Rates & Regulatory.

B. Time Reporting

When a DEC/DEP/Piedmont employee supports an Affiliate/Nonpublic Utility Operation:

1. Hours worked by DEC/DEP/Piedmont employees in direct support of an Affiliate/Nonpublic Utility Operation are charged directly to the Affiliate/Nonpublic Utility Operation.
2. Overtime hours worked by a non-exempt employee during a week should be applied first to the Affiliate/Nonpublic Utility Operation project, up to total hours worked on the project.
    a) If overtime pay is charged to the utility but not the Affiliate/Nonpublic Utility Operation in a time reporting period, the reason for the exception shall be fully documented and maintained by the supervisor for a minimum of two years.
    b) For example, a non-exempt employee works 50 hours for a given week, 10 of which must be paid as overtime. Twenty of the 50 hours were in support of an Affiliate project. That project should be charged 10 hours overtime and 10 hours straight-time.
3. When an exempt employee who is paid semi-monthly provides support to an Affiliate/ Nonpublic Utility Operation, and overtime is worked, the employee's regular semi-monthly pay is prorated to the utility and the Affiliate/Nonpublic Utility Operation based on the number of hours worked for each.
4. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for vacation carryover or paid supplemental compensation.

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5. The financial system will automatically load time reported to an Affiliate/Nonpublic Utility Operation with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the business finance support group to appropriately adjust the costs to market. The overhead cost factor includes the following components: department administrative overheads, corporate governance, employee training, Service Company-related shared services, facilities, and supervisory costs.

C. Labor Allocations

DEC/DEP/Piedmont employees may provide services to their regulated Utility Affiliates at DEC's, DEP's, or Piedmont's fully distributed costs and DEC/DEP/Piedmont employees may provide services to Duke Energy Corporation, a Non-Utility Affiliate, a non-regulated Utility Affiliate or Nonpublic Utility Operation at the higher of fully distributed cost or market value, subject to certain exceptions. The mechanism for charging is generally a cost applied to labor charges and a market value journal entry if applicable. Allocation rates described in items 1 through 10 below are applied as a cost factor to direct labor charged to an Affiliate/Nonpublic Utility Operation.

Below are the various cost components of labor loads. The rates for Items 1-4 may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 are components of Duke Energy's Regulated Utilities Franchised Electric and Gas labor cost multiplier and are updated annually. Items 5-10 do not apply to transactions between DEC and DEP.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement, and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are

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charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. **Incentive Allocation**

   Incentives are accrued via a loading factor applied to direct labor charges by the DEC/DEP/Piedmont employee performing work for an Affiliate/Nonpublic Utility Operation.

4. **Unproductive Cost Allocation**

   An unproductive cost allocation is applied on the basis of direct labor charges by the DEC/DEP/Piedmont employee performing work for an Affiliate/Nonpublic Utility Operation. DEC/DEP/Piedmont allocates unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Duke Energy intends to calculate Items 5-10 below on a total Regulated Utilities Franchised Electric and Gas basis with the calculations to be performed annually. Annualized costs (either historic or projected) that best align with the current organization will be used in the calculations.

5. **Administrative Overheads**

   An Administrative Overhead Rate will be applied on the basis of direct labor charges. Administrative Overheads include: Departmental administrative functions (Business Support and General Office Executive Management), labor, and non-labor costs (e.g., training, employee expenses, Information Management costs for administrative functions by functional department).

6. **Corporate Governance**

   A corporate governance cost rate is applied on the basis of direct labor charges. The corporate governance rate is based on corporate governance costs allocated to FE&G.

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7. Employee Training Costs

An employee training cost rate is applied on the basis of direct labor charges. The employee training-related costs factor will be developed by identifying the direct labor charges for those within Regulated Utilities that perform employee training-related tasks. Such training provides employees with the knowledge and skills necessary to perform their job duties, for professional development, and to maintain professional or technical licenses or for certifications required for business operations. The employee training cost rate is based on the total direct labor charges of the groups within Regulated Utilities that perform employee training-related tasks.

8. Service Company Costs

A service company cost rate is based on historical enterprise and governance overhead charged to Regulated Utilities in the following functions: Information Systems, Transportation, Human Resources, Materials Management, Accounting, Public Affairs, Legal, Finance, Facilities, Internal Auditing, Environmental, Health and Safety, Investor Relations, Planning, and Executive.

9. Facilities Cost

The facilities cost rate is applied on the basis of direct labor charges. The facility cost rate is based on the annual cost structure for corporate facilities, i.e., Charlotte, Raleigh, Cincinnati, St. Petersburg and Plainfield office buildings, and the number of employees occupying these facilities to arrive at an average facility cost.

10. Supervisory Costs

The supervisory cost rate is applied on the basis of direct labor charges. The supervisory cost rate represents the cost of supervision related to a Regulated Utilities employee performing work for an Affiliate Business unit. The basis for determining such costs is through the analysis of supervisory labor cost as a factor of Regulated Utilities employee labor cost.

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D. Premium Services (Non-affiliate transactions)

Premium services are unregulated services provided by DEC or DEP to its electric customers. All costs related to premium services are either direct-charged or allocated to non-utility accounts. Costs identified in subsections C.1. through C.4. above are automatically allocated based on labor charges to premium services processes. An additional multiplier rate is also applied to labor charged to these premium services processes to cover costs such as facilities, administrative and corporate overheads, employee training and supervision, and shared services.

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J. UTILITY TO UTILITY COST DISTRIBUTION DETAILS

The following are Utility allocations that run on Duke Energy Carolinas and Duke Energy Progress:

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2019 Utility Level allocations

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	Alloc Pool Description	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Electric Utilities	Total Gas Utilities	Total
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	CTTR	Electric System	BSS Elec Tran Utility	CTTCMETR	BSS Elec Tran Utility	C15	40.89	19.53	15.43	16.60	0.33	7.22	100.00	-	100.00
			PTTR	Electric System	BSS Elec Tran Utility	PCTTCMETR	BSS Elec Tran Utility	C15	40.89	19.53	15.43	16.60	0.33	7.22	100.00	-	100.00
			CTDC	Electric System	BSS Elec Tran Utility	DCDCOMET	BSS Elec Tran Utility	C58	67.68	32.32	-	-	-	-	100.00	-	100.00
			PTPC	Electric System	BSS Elec Tran Utility	PCDCOMET	BSS Elec Tran Utility	C58	67.68	32.32	-	-	-	-	100.00	-	100.00
	Services related to distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	CTDI	Electric System	BSS Elec Dist Utility	CTDCMEDT	BSS Elec Dist Utility	C16	39.27	25.58	16.38	11.38	1.10	6.29	100.00	-	100.00
			PTDI	Electric System	BSS Elec Dist Utility	PCTDCMEDT	BSS Elec Dist Utility	C16	39.27	25.58	16.38	11.38	1.10	6.29	100.00	-	100.00
			CDDC	Electric System	BSS Elec Dist Utility	DCDCMED	BSS Elec Dist Utility	C93	60.56	39.44	-	-	-	-	100.00	-	100.00
			DPPC	Electric System	BSS Elec Dist Utility	PCDCMED	BSS Elec Dist Utility	C93	60.56	39.44	-	-	-	-	100.00	-	100.00
									-	-	-	-	-	-	-	-	-
Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*	CTSD	M&CR	M&CR Sales & Demand Util	CUTSALMCR	M&CR Sales & Demand Util	C17	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			PCSD	M&CR	M&CR Sales & Demand Util	PCUTSALST	M&CR Sales & Demand Util	C82	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			MSPS	M&CR	Mkt Sol - DEP Leg Duk	DEPSALSTD	Market Solutions - DEP LD Std	U04	60.79	-	-	19.21	3.31	16.69	100.00	-	100.00
			CNET	M&CR	Customer Strategy P&S	CUTSALNET	Customer Strategy P&S	C75	60.79	-	-	19.21	3.31	16.69	100.00	-	100.00
			PCNT	M&CR	Customer Strategy P&S	PCUTSALNE	Customer Strategy P&S	C83	60.79	-	-	19.21	3.31	16.69	100.00	-	100.00
			CSTD	M&CR	Standard Services	CUTSALSTD	Standard Services	C17	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			MSCS	M&CR	Mkt Sol - DEC Duke Std	DECSALSTD	Market Solutions DEC LD Std	U03	60.79	-	-	19.21	3.31	16.69	100.00	-	100.00
			CTNT	M&CR	M&CR Sales&Demand Utl	CUTCLSMCR	M&CR Electric Utility	C74	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
			PCNA	M&CR	PEC Customer Elec Only	PCUSELEC	PEC Customer Elec Only	C78	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
			PFNA	M&CR	DEF Customer Elec Only	DECUSELEC	DEF Customer Elec Only	C79	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
									-	-	-	-	-	-	-	-	-
	Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	CTMR	M&CR	M&CR Mtr Rdg&Pmt Proc Util	CUTCOLSPMT	M&CR Mtr Rdg&Pmt Proc Util	C37	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			PCRA	M&CR	M&CR Mtr Rdg&Pmt Proc Util	PCUTCOLSPM	M&CR Mtr Rdg&Pmt Proc Util	C85	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			PFPA	M&CR	M&CR Mtr Rdg&Pmt Proc Util	PUTCOLSPMT	M&CR Mtr Rdg&Pmt Proc Util	C89	54.09	-	-	17.09	2.94	14.85	88.97	11.03	100.00
			CUMR	M&CR	M&CR Customers Util ND	CUTCUSPMT	M&CR Customers Util ND	C38	31.75	19.25	22.04	10.03	1.73	8.72	93.52	6.48	100.00
			CUMS	M&CR	Mkt Sol - DEC Utilities Std	CUTCUSPAY	Market Solutions - DEC All Util	C99	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
			POMR	M&CR	M&CR Customers Util ND	POUTCUSPM	M&CR Customers Util ND	C84	31.75	19.25	22.04	10.03	1.73	8.72	93.52	6.48	100.00
			POMS	M&CR	Mkt Sol - DEP Util Std	POUTCUSPAY	Market Solutions DEP All Util	U02	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
			PRMR	M&CR	M&CR Customers Util ND	PUTCUSPMT	M&CR Customers Util ND	C88	31.75	19.25	22.04	10.03	1.73	8.72	93.52	6.48	100.00
			PRMS	M&CR	Mkt Sol - DEF Util Std	PUTCUSPAY	Market Solution DEF All Util	U01	33.96	20.58	23.56	10.73	1.85	9.32	100.00	-	100.00
			PRMW	M&CR	DEF M&CR Mtr Rdg&PmtPrc Util	PUTMOLSPMT	DEF M&CR Mtr Rdg&PmtPrc Util	C60	-	-	-	37.22	6.41	32.34	75.97	24.03	100.00
									-	-	-	37.22	6.41	32.34	75.97	24.03	100.00
			GMMR	M&CR	M&CR Mtr Rdg&PmtPrc Util MWonly	CUTMOLSPMT	M&CR Mtr Rdg&PmtPrc Util MWonly	C60	-	-	-	-	-	-	-	-	-
Electric Transmission & Distribution Engineering & Construction - Designs and monitors construction of electric T & D lines and substations. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.	Transmission engineering and construction:	*(Electric Transmission Plant's) Construction - Expenditures Ratio*	CTET	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ET Utility	CTCDONETR	Eng & Constr ET Utility	C18	23.10	14.97	39.06	10.57	1.15	11.15	100.00	-	100.00
			PTET		Eng & Constr ET Utility	PCTCDONETR	Eng & Constr ET Utility	C18	23.10	14.97	39.06	10.57	1.15	11.15	100.00	-	100.00
	Distribution engineering and construction:	*(Electric Distribution Plant's) Construction - Expenditures Ratio*	CTED	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ED Utility	CTCDONEDT	Eng & Constr ED Utility	C30	29.27	23.21	21.79	13.38	1.57	10.78	100.00	-	100.00
									-	-	-	-	-	-	-	-	-
			PTED		Eng & Constr ED Utility	PCTCDONE DT	Eng & Constr ED Utility	C30	29.27	23.21	21.79	13.38	1.57	10.78	100.00	-	100.00
Power Engineering & Construction - Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	Generation engineering and construction:	*(Electric Production Plant's) Construction - Expenditures Ratio*	CTCE	Power Engineering & Construction	Eng & Constr Pwr Prod Util	CTCDONPWR	Eng & Constr Pwr Prod Util	C25									
									34.49	30.03	15.59	14.05	5.84	-	100.00	-	100.00

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2019 Utility Level allocations

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	Alloc Pool Description	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	Total DEK	Total DEO	Total Electric Utilities	Total Gas Utilities	Total
Power Planning and Operations - Coordinates the planning, management and operation of Duke Energy Corporation's electric power systems. The activities of the Function include System Planning - planning of additions and retirements to Duke Energy Corporation's electric generation, transmission and distribution systems.	Generation planning:	*Elec Peak Load Ratio*	CTGE	Power Planning and Ops	Pwr Plng&Ops Gen Plng Util	CTPKLGPL	Pwr Plng&Ops Gen Plng Util	C21	37.79	28.24	19.81	12.47	1.69	-	100.00	-	100.00
	Transmission planning:	*Elec Peak Load Ratio*	CTTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util	CTPKLETR	Pwr Plng&Ops Trans Plng Util	C32	37.91	22.77	19.51	11.74	1.30	6.77	100.00	-	100.00
	Transmission planning:	*Elec Peak Load Ratio*	PTTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util	PCTTPKLETR	Pwr Plng&Ops Trans Plng Util	C32	37.91	22.77	19.51	11.74	1.30	6.77	100.00	-	100.00
	Distribution planning:	Weighted Avg of the *Circ Miles of ED Lines Ratio* and the *Elec Peak Load Ratio*	CTDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util	CTDMEDL	Pwr Plng&Ops Dist Plng Util	C41	38.57	24.18	17.95	11.56	1.20	6.54	100.00	-	100.00
									-	-	-	-	-	-	-	-	
	Distribution planning:	Weighted Avg of the *Circ Miles of ED Lines Ratio* and the *Elec Peak Load Ratio*	PTDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util	CTDMEDL	Pwr Plng&Ops Dist Plng Util	C41	38.57	24.18	17.95	11.56	1.20	6.54	100.00	-	100.00
									-	-	-	-	-	-	-	-	
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	*Sales Ratio*	CTGD	Power Planning and Ops	Pwr Plng&Ops Gen Dsptch Util	CTSALGDP	Pwr Plng&Ops Gen Dsptch Util	C42	27.00	23.12	26.58	20.15	3.15	-	100.00	-	100.00
	Transmission Operations:	Weighted Average of the *Circ Miles of Elec Transm Lines Ratio* and the *Elec Peak Load Ratio*	CTTO	Power Planning and Ops	Pwr Plng&Ops Trans Ops Util	CTTOMDTR	Pwr Plng&Ops Trans Ops Util	C31	39.39	21.15	17.47	14.17	0.82	7.00	100.00	-	100.00
									-	-	-	-	-	-	-	-	
									-	-	-	-	-	-	-	-	
	Distribution Operations :	Weighted Avg of the *Circ Miles of ED Lines Ratio* and the *Elec Peak Load Ratio*	CTDO	Power Planning and Ops	Pwr Plng & Ops Dist Ops Util	CTDMEDOL	Pwr Plng & Ops Dist Ops Util	C22	38.57	24.18	17.95	11.56	1.20	6.54	100.00	-	100.00
									-	-	-	-	-	-	-	-	
									-	-	-	-	-	-	-	-	
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.	*Generating Unit MW Capability/MDC Ratio*	CEPO	Power Planning and Ops	Pwr Plng & Ops Pwr Ops Reg	CEGOAPROP	Pwr Plng & Ops Pwr Ops Reg	C28	29.28	24.15	24.36	19.32	2.89	-	100.00	-	100.00
									-	-	-	-	-	-	-	-	
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Sales Ratio*	CTEA	Environmental, Health and Safety	Enviro Affairs Svcs Utility	CTSALENV	Enviro Affairs Svcs Utility	C47	28.87	20.71	13.58	10.61	1.34	6.66	81.77	18.23	100.00
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	CTHS	Fuels	Fuels Utility	CUFTSALHS	Fuels Utility	C48	27.00	23.12	26.58	20.15	3.15	-	100.00	-	100.00
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
									-	-	-	-	-	-	-	-	-
Nuclear	Provides general support services for the Nuclear fleet.	*Generating Unit MW Capability/MDC Ratio*	CNUE	Nuclear	DEC Nuclear Fixed Distribution	CUNUCBKGI	DEC Nuclear Fixed Distribution	C49	66.70	33.30	-	-	-	-	100.00	-	100.00
			PNUC	Nuclear	PEC Nuclear Fixed Distribution	PUNUCLBKGI	PEC Nuclear Fixed Distribution	C50	66.70	33.30	-	-	-	-	100.00	-	100.00
Fossil Hydro	Coal Combustion - provides centralized management, governance and support services for Duke Energy's Corporation's coal cumbustion residuals	*MDC Ratio*	CCPD	Fossil	Coal Combustion Products	DEC_CCPD	FHO Coal Comb Prod Util DEC	CCA	33.73	56.67	0.48	8.57	0.55	-	100.00	-	100.00
			CCPP	Fossil	Coal Combustion Products CAPEX	DEC_CCCP	CCP CAPEX Alloc	CPP	31.03	19.86	15.06	15.22	18.83	-	100.00	-	100.00
			CCDM	Fossil	Coal Combustion Products O&M	DEC_CCDM	CCP O&M Alloc	CCP	43.64	25.46	-	27.12	3.78	-	100.00	-	100.00
			CCPC	Fossil	Coal Combustion Products ARO		Coal Combustion Products ARO	AR3	100.00	-	-	-	-	-	100.00	-	100.00
			CCCC	Fossil	Coal Combustion Products Capital Additions		Coal Combustion Products Capital Additions	C41	100.00	-	-	-	-	-	100.00	-	100.00

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K. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH UTILITY AFFILIATES EXCLUDING THE SERVICE COMPANY

On occasion, Utility Affiliate (DEF, DEI, DEK, DEO-Transmission or DEO - Distribution) employees may be requested to provide support, subject to availability, to DEC/DEP/Piedmont. Affiliate management is responsible for ensuring that the use of all company resources to support DEC/DEP/Piedmont is properly charged to DEC/DEP/Piedmont. The Utility Affiliate will charge its fully distributed cost to DEC/DEP/Piedmont. Charging DEC/DEP/Piedmont fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. The Utility Affiliate management is accountable for the review and approval of all charges from the Utility Affiliate in support of DEC/DEP/Piedmont work. An Affiliate Rules and Transactions CBT (emphasis on DEC/DEP/Piedmont) is available in the Training Connection on the Portal.

Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, which addresses eliminating a utility affiliate loader between DEC and DEP. The following procedure addresses the responsibilities of employees and management.

A. General Guidelines

1. Hours worked by the Utility Affiliate employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. First-line supervisors should review and approve, when appropriate, source documentation resulting in a charge by Utility Operations to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors/managers are responsible for reviewing any reports that detail monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to DEC/DEP/Piedmont.

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4. Utility Affiliate to DEC/DEP/Piedmont transactions typically require the completion and approval of a Service Request form, unless DEC/DEP/Piedmont is requesting the service from the other. The process and eForm can be found on the Portal under Rates & Regulatory.

B. Time Reporting

When a Utility Affiliate employee supports DEC/DEP/Piedmont:

1. Hours worked by the Utility Affiliate employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for vacation carryover or paid supplemental compensation.
3. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the Regulated Utility Financial Planning & Analysis group to appropriately adjust the costs to market. The overhead cost factor includes the following components: department administrative overheads, corporate governance, employee training, Service Company-related shared services, facilities, and supervisory costs.

C. Labor Allocations

Utility Affiliate employees provide services to DEC/DEP/Piedmont at fully distributed cost. The mechanism for charging DEC/DEP/Piedmont is generally a cost adder applied to labor charges and a market value journal entry if applicable. Allocation rates described in items 1 through 10 below are applied as a cost factor to direct labor charged to DEC/DEP/Piedmont. Below are the various cost components of labor loads. The rates for Items 1-4 may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 are components of Duke Energy's Regulated Utilities labor cost multiplier and are updated annually.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These

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costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

2. **Payroll Tax Allocation**

   Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. **Incentive Allocation**

   Incentives are allocated via a loading factor applied to direct labor charges by each Utility Affiliate employee performing work for DEC/DEP/Piedmont.

4. **Unproductive Cost Allocation**

   An unproductive cost allocation is applied on the basis of direct labor charges by each Utility Affiliate employee performing work for DEC/DEP/Piedmont. Each Utility Affiliate allocates unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Duke Energy intends to calculate Items 5-10 below on a total Regulated Utilities basis with the calculations to be performed annually. Annualized costs (either historic or projected) that best align with the current organization will be used in the calculations. Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, details of Items 5-10. Items 5-10 do not apply to transactions between DEC and DEP.

5. **Administrative Overheads**
6. **Corporate Governance**
7. **Employee Training Costs**
8. **Service Company Costs**
9. **Facilities Cost**
10. **Supervisory Costs**

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L. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH NON-REGULATED AFFILIATES

On occasion, employees of Non-Regulated Affiliates may be requested to provide support, subject to availability, to DEC/DEP/Piedmont. (Non-Regulated Affiliates' management is responsible for ensuring that use of all company resources to support DEC/DEP/Piedmont work is properly charged to DEC/DEP/Piedmont.) Rules regarding affiliate agreements between Non-Regulated Affiliates and DEC/DEP/Piedmont are described in Section E. *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates* incorporated in this CAM. Non-Regulated Affiliates will charge DEC/DEP/Piedmont the lower of fully distributed cost or market value as appropriate. Charging DEC/DEP/Piedmont either market or fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. Non-Regulated management is accountable for the review and approval of all charges from Non-Regulated Affiliates in support of DEC/DEP/Piedmont's work.

The following procedure addresses employee's and manager's responsibilities.

A. General Guidelines

1. Hours worked by employees of Non-Regulated Affiliates in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. First-line supervisors should review and approve, when appropriate, any source documentation resulting in a charge by Non-Regulated Affiliates to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include charges incurred by the responsibility center to DEC/DEP/Piedmont.
4. Non-Regulated to DEC/DEP/Piedmont transactions typically require the completion and approval of a Service Request form. The process and eForm can be found on the Portal under Rates & Regulatory.

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B. Time Reporting

When a Non-Regulated employee supports DEC/DEP/Piedmont:

1. Hours worked by Non-Regulated employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for vacation carryover or paid supplemental compensation.
3. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the Non-Regulated Affiliate's financial group to appropriately adjust the costs to market.

C. Labor Allocations

Non-Regulated employees provide services to DEC/DEP/Piedmont at the lower of fully distributed cost or market value. The mechanism for charging DEC/DEP/Piedmont is generally a cost adder applied to labor charges. When appropriate to charge market, a market value journal entry is made. Allocation rates described in items 1 through 10 may be applied as a cost factor to direct labor when charging DEC/DEP/Piedmont.

Below are the various cost components of labor loads which may be applied to labor when Non-Regulated Affiliates do work for and charge DEC/DEP/Piedmont. The rates for Items 1-4 (specific to Non-Regulated Affiliates) may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 may also be included as components of Non-Regulated Affiliates' labor cost multiplier.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

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2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. Incentive Allocation

Incentives are allocated via a loading factor applied to direct labor charges by the Non-Regulated employee performing work for DEC/DEP/Piedmont.

4. Unproductive Cost Allocation

An unproductive cost allocation is applied on the basis of direct labor charges by the Non-Regulated employee performing work for DEC/DEP/Piedmont. Non-Regulated Affiliates allocate unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, details of Items 5-10.

5. Administrative Overheads

6. Corporate Governance

7. Employee Training Costs

8. Service Company Costs

9. Facilities Cost

10. Supervisory Costs

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M. TYPICAL TRANSACTIONS BETWEEN DEC/DEP/PIEDMONT AND AFFILIATES COVERED UNDER SEPARATE AGREEMENTS

The following are some of the typical transactions that DEC/DEP/Piedmont conduct with one another or their affiliates under separate agreements not otherwise discussed in this manual. These agreements and others can be found on the State Regulatory Compliance portal page.

A. Bison Insurance

Duke Energy's Insurance program requires that costs be identified and allocated to the business units based upon their contributions to the risk of the entire company. The programs are designed to encourage risk control, early claims reporting, and efficient claims management and allow for cost-based pricing. This is accomplished by transferring the insurable losses across the company to the captive insurance companies, generally after a small business unit deductible is met. The captives also reinsure their risk in excess of its retention (and additional deductible) with unrelated third-party reinsurance companies. The captives charge premiums to business units that participate in the program to cover the aggregate cost of reinsurance and the estimated retained losses at the captives. This works essentially the same way commercial insurance works where the losses of a few are covered by the premiums of many.

The primary types of costs to be allocated are:

- retained losses and related loss adjustment expenses
- insurance premiums

Duke Energy has developed specific premium calculation methodologies for each line of coverage (i.e., general liability, property, workers' compensation and directors and officers), which is similar to how commercial insurance underwrites risk. Insurance premiums (costs) are generally allocated on a blended basis of exposure and historical loss experience (frequency and severity).

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B. Intercompany Asset Transfer Agreement

An agreement among DEC, DEP, DEF, DEO, DEI, DEK, and Piedmont addresses the transfer of assets, compensation, payment, warranties, and indemnification. The Commission approved a limited waiver of the cost-based pricing provisions of the Intercompany Asset Transfer Agreement for the transfer between DEC and DEP of rotable fleet spares, which are specific working parts of a generating unit that must be replaced several during the relatively long life of that unit. *Order Approving Request for Limited Waiver and Pre-Approval of Accounting Authority Pursuant to Rule R8-27*, Docket No. E-2, Sub 998A, E-7, Sub 986A (Sept. 3, 2014).

C. Tax Sharing Agreement

Duke Energy Corporation, as parent of a consolidated group of companies, files federal income taxes on behalf of its affiliates who are members of its consolidated group. Under Duke Energy Corporation's Tax Sharing Agreement, which is applicable to all members of Duke Energy's consolidated group, income taxes allocable to Duke Energy Corporation are accrued by it and consolidated group members on a stand-alone basis.

D. Utility Money Pool Agreement

Establishes a cash management program (the "Utility Money Pool") to coordinate and provide for certain short-term cash and working capital requirements.

E. Carolinas Operating Companies Commodity and Related Equipment and Services Transfer Agreement

Provides for the pre-approved transfer of fuel, reagents, coal combustion products, and related equipment and services (but does not provide for the disposal of coal combustion products). See *Order Accepting Affiliate Agreement and Allowing Payment Thereunder*, Docket Nos. E-2, Sub 998A and E-7, Su b 986A (Feb. 10, 2015).

F. Asset Management and Delivered Supply Agreement (AMA)

Provides for DEC to be the asset manager for all natural gas supply and capacity for both DEC and DEP. The AMA facilitates coordination and optimization of natural gas capacity and supply rights owned by DEC and DEP to reduce the cost of providing electric service to both DEC's and DEP's native load customers.

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N. OTHER

Audit Principles & Guidelines

An audit trail shall exist with respect to transactions between DEC/DEP/Piedmont and its affiliates.

Corporate Audit Services will have complete access to affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with established policies and procedures and regulatory requirements. Auditors will have complete access to affiliate records to ensure availability of relevant information necessary to evaluate whether subsidization exists. The auditors, not the individual affiliates, will determine what is relevant for a particular audit objective. Limitation of access would compromise the audit process and impair audit independence.

Cost allocation documentation will be made available to Corporate Audit Services for periodic review of the allocation policies and procedures and to any jurisdictional regulatory authority when appropriate and upon request. Any entity required to provide access to its books and records can, and is encouraged to, make arrangements as necessary and appropriate to ensure that competitively sensitive information provided in the course of the audits be kept confidential by Corporate Audit Services and/or regulatory authorities.

Transactions between DEC/DEP/Piedmont and its Affiliates/Nonpublic Utility Operations will be reviewed at a minimum annually by Corporate Audit Services.

Kendrick C. Fentress
Associate General Counsel

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Mar 31 2020

March 31, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Cost Allocation Manual
Docket Nos. E-7, Sub 1100A; E-2, Sub 1095A; and G-9, Sub 682A

Dear Ms. Campbell:

Pursuant to Regulatory Condition No. 5.5(c) set forth in the Commission's *Order Granting Motion to Amend Regulatory Conditions* issued on August 24, 2018, enclosed for filing is the 2020 Cost Allocation Manual ("CAM") of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc. in the referenced dockets.

During the review of allocation factors in 2019 in preparation for the 2020 Budget and Calendar year actuals, there were no changes deemed necessary to the allocation bases currently being used to allocate the various services.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of the 2020 Cost Allocation Manual of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc., in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A and G-9, Sub 682A, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 31st day of March, 2020.

Kendrick C. Fentress

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Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont)

Cost Allocation Manual - 2020

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A. INTRODUCTION

This Carolinas' Cost Allocation Manual ("CAM") documents the guidelines and procedures for allocating costs between the different business units impacting DEC, DEP, and Piedmont. The guidelines are intended to provide the foundation for proper identification and recording of transactions involving the exchange of services or goods between DEC, DEP, Piedmont and their Affiliates. These guidelines describe the allocation methods that are consistent with cost causation principles to ensure one Duke Energy entity does not subsidize another. Additional information on Duke Energy's internal controls and finance policies is available for Duke Energy employees on the employee Portal.

Per the Regulatory Conditions in the *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct* issued September 29, 2016 by the North Carolina Utilities Commission ("Commission") in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, as amended by the *Order Granting Motion to Amend Regulatory Conditions* issued by the Commission in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A, the following merger conditions apply to the CAM:

5.5 Charges for and Allocations of the Costs of Affiliate Transactions.

To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC, DEP, and Piedmont shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DEC, DEP, or Piedmont, any Utility Affiliate, DEBS, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to DEC, DEP, or Piedmont. Piedmont will adopt DEC's and DEP's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DEC, DEP, Piedmont, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DEC, DEP, and Piedmont shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC, DEP, or Piedmont has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice Is Required.

With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15-day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC, DEP, or Piedmont may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

In addition to the CAM as a cost charging guide, DEC, DEP, and Piedmont use OpenPages to track compliance with regulatory requirements. OpenPages is administered by Corporate Compliance, which serves DEC, DEP, and Piedmont. OpenPages allows a regulatory requirement to be broken down into actionable tasks and assigned to one or more individuals. Individuals must complete tasks assigned and report completion by a certain date. OpenPages is integral to DEC's, DEP's, and Piedmont's culture of compliance.

B. SUMMARY OF CORPORATE STRUCTURE [1]

AS OF DECEMBER 31, 2019

- Duke Energy Corporation
  - Bison Insurance Company Limited
    - NorthSouth Insurance Company Limited
  - Cinergy Corp.
    - Cinergy Global Resources, Inc.
    - Duke Energy Renewables Holding Company, LLC
      - Duke Energy Breeze Holdings, LLC
      - Duke Energy Commercial Enterprises, Inc.
      - Duke Energy Renewables, Inc.
        - Duke Energy Renewables Commercial, LLC
        - Duke Energy Renewables Solar, LLC
        - Duke Energy Renewables Wind, LLC
        - Duke Energy Renewable Services, LLC
        - REC Solar Commercial Corporation
        - Duke Ventures II, LLC
        - Symphony Wind Holdings, LLC
        - Duke Energy Renewables Storage, LLC
        - Duke Energy Renewables Solar Holdings, Inc.
        - Duke Energy Sun Holdings, LLC
    - Cinergy Receivables Company, LLC
    - Duke Energy Indiana, LLC
    - Duke Energy Ohio, Inc.
      - Duke Energy Beckjord, LLC
      - Duke Energy Kentucky, Inc.
      - KO Transmission Company
      - Miami Power Corporation
      - Ohio Valley Electric Corporation
      - Tri-State Improvement Company
    - Duke Energy SAM, LLC
    - Duke Energy Transmission Holding Company, LLC
    - Duke Technologies, Inc.
      - Duke Energy One, Inc.
    - Progress Fuels, LLC
  - Duke Energy Clean Energy Resources, LLC
  - Duke Energy Renewables NC Solar, LLC
  - Duke Energy Pipeline Holding Company, LLC
    - Duke Energy ACP, LLC
    - Duke Energy Sabal Trail, LLC
    - Piedmont ENCNG Company, LLC
    - Piedmont Constitution Pipeline Company, LLC
    - DEPHCO Logistics, LLC
  - Duke Energy Carolinas, LLC
  - Duke Energy Corporate Services, Inc.
    - Duke Energy Business Services LLC
  - Duke Energy Registration Services, Inc.
    - Duke Energy Americas, LLC

        - Duke Energy International, LLC
- Progress Energy, Inc.
    - Duke Energy Progress, LLC
    - Florida Progress, LLC
        - Duke Energy Florida, LLC
    - Strategic Resource Solutions Corp.
- Piedmont Natural Gas Company, Inc.
    - Piedmont Energy Partners, Inc.
    - Piedmont Hardy Storage Company, LLC

[1] This presentation of the Duke Energy Corporation Corporate Structure is a simplified and partial legal entity view.

C. NORTH CAROLINA CODE OF CONDUCT

(as approved by the North Carolina Utilities Commission)

This section contains the complete text of the "official" North Carolina Code of Conduct (hereinafter "Code of Conduct" or "Code"), approved by the North Carolina Utilities Commission, which governs DEC's, DEP's, and Piedmont's transactions with affiliates. This Code applies in North Carolina and South Carolina.

CODE OF CONDUCT

GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF DEP, THE PUBLIC UTILITY OPERATIONS OF PIEDMONT, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC, DEP, AND PIEDMONT

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Nonpublic information that pertains to Electric Services provided by DEC or DEP, including but not limited to information concerning electric generation, transmission, distribution, or sales, and nonpublic information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress, LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, is the current holding company parent of DEC, DEP, Piedmont, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or DEP from sources other than DEC or DEP for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Natural Gas Services: Commission-regulated natural gas sales, natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, and standby service.

Non-affiliated Gas Marketer: An entity, not affiliated with DEC, DEP, or Piedmont, engaged in the unregulated sale, arrangement, brokering, or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operation: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Personnel: An employee or other representative of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP, is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC, DEP, and

Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Non-affiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated public utility operations of Duke Energy Florida, LLC ("DEF"), Duke Energy Indiana, LLC ("DEI"), Duke Energy Kentucky, Inc. ("DEK") and Duke Energy Ohio, Inc. ("DEO").

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, and Piedmont, to the extent such relationships, activities, and transactions affect the public utility operations of DEC, DEP, and Piedmont in their respective service areas. DEC, DEP, Piedmont, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DEC, DEP, or Piedmont may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, DEP, Piedmont, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable; however, to the extent that the Commission has approved or accepted a service company-to-utility or utility-to-utility service agreement or list, DEC, DEP, Piedmont, Duke Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DEC, DEP, Piedmont, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's, DEP's, and Piedmont's Nonpublic Utility Operations shall maintain separate records from those of DEC's, DEP's, and Piedmont's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC, DEP, and Piedmont may provide Customer Information to Duke Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.

(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DEC, DEP, and Piedmont or to DEC's or DEP's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC, DEP, and Piedmont retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

(c) If the Customer allows or directs DEC, DEP, or Piedmont to provide Customer Information to Duke Energy, another Affiliate, or to DEC's or DEP's Nonpublic Utility Operations, then DEC, DEP, or Piedmont shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC, DEP, or Piedmont to provide the Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2. shall be permanently posted on DEC's, DEP's and Piedmont's website(s).

(e) No DEC, DEP, or Piedmont employee who is transferred to Duke Energy or another Affiliate, shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to a signed Data Disclosure Authorization. DEC, DEP, and Piedmont shall

not transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions in this Section III.A.2.:

(i) DEC, DEP, and Piedmont may disclose Customer Information to DEBS, any other Affiliate, or a non-affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DEC, DEP, or Piedmont and upon the written agreement of the other Affiliate or non- affiliated third-party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC or DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DEC, DEP, and Piedmont may disclose Customer Information to a state or federal regulatory agency or court of competent jurisdiction if required in writing to do so by the agency or court.

(g) DEC, DEP, and Piedmont shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC, DEP, and Piedmont shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS employee may use Customer Information to market or sell any product or service to DEC's, DEP's, or Piedmont's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC, DEP, or Piedmont.

(j) DEBS employees with access to Customer Information must be prohibited from making any improper indirect use of the data,

including directing or encouraging any actions based on the Customer Information by employees of DEBS that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and DEP.

(k) Should any inappropriate disclosure of DEC, DEP, or Piedmont Customer Information occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

3. The disclosure of Confidential Systems Operation Information of DEC, DEP, and Piedmont shall be governed as follows:

(a) Such CSOI shall not be disclosed by DEC, DEP, or Piedmont to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is provided to employees of DEC or DEP for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

(ii) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.

(iii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.

(iv) The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.

(v) The CSOI is provided to employees of DEC's, DEP's, or Piedmont's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.

(vi) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.

(vii) Disclosure is otherwise essential to enable DEC or DEP to provide Electric Services to their Customers or for Piedmont to provide Natural Gas

Services to its Customers.

(viii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any CSOI disclosed pursuant Section III.A.3.(a)(i)-(viii) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the CSOI to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vii) and (viii), DEC, DEP, and Piedmont shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;
(ii) The reasons for the disclosure; and
(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, DEP, Piedmont, and DEBS employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC, DEP, and Piedmont.

(e) Should the handling or disclosure of CSOI by DEBS, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DEC's or DEP's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet

website, or (iii) other public disclosure of the data, DEC or DEP shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, and E-2, Sub 1095C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, E-2, Sub 1095C, or G- 9, Sub 682C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and DEP shall file a letter with the Commission in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's, DEP's, and Piedmont's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, Natural Gas Services, or both, DEC, DEP, and Piedmont shall not provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, DEP, Piedmont, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC, DEP, and Piedmont shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC, DEP, and Piedmont shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC, DEP, or Piedmont; provided however, that this prohibition shall not apply to employees of DEBS providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's, DEP's, or Piedmont's regulated public utility operations.

6. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or Natural Gas Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. DEC, DEP, and Piedmont shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC, DEP, or Piedmont receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers.

11. Piedmont shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

C. Marketing

1. The public utility operations of DEC, DEP, and Piedmont may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to

compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DEC, DEP, and Piedmont shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC, DEP, or Piedmont in any communications without the following disclaimer:

(a) "[Duke Energy Corporation/Affiliate] is not the same company as [DEC/DEP/Piedmont], and [Duke Energy Corporation/Affiliate] has separate management and separate employees";

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/DEP/Piedmont]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/DEP] or natural gas service from Piedmont."

3. Nonpublic Utility Operations may not use the names or logos of DEC, DEP, or Piedmont in communications without the following disclaimer:

"[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/DEP/Piedmont] and is not in any way sanctioned by the North Carolina Utilities Commission."

4. In addition, DEC's and DEP's Nonpublic Utility Operations may not use the names or logos of DEC or DEP in any communications without the following disclaimers:

(a) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/DEP]"; and

(b) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/DEP]."

The required disclaimers in this Section III.C.4. must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the

larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC, DEP, or Piedmont for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC, DEP, or Piedmont, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's, DEP's, or Piedmont's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DEC, DEP, or Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC, DEP, or Piedmont shall be set at the higher of Market Value or DEC's, DEP's, or Piedmont's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS, or a Nonpublic Utility Operation to DEC, DEP, or Piedmont, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC, DEP, or Piedmont shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC, DEP, or Piedmont do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC, DEP, and Piedmont shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's, DEP's, and Piedmont's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by DEBS to DEC, DEP, Piedmont, and Utility Affiliates, the transfer price charged shall be set at DEBS' Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC, DEP, and Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to

Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC, DEP, or Piedmont to DEC, DEP, Piedmont, or the Utility Affiliates or by the Utility Affiliates to DEC, DEP, or Piedmont, shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its *Order Approving Stipulation*, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

4. To the extent that DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS (or its successor), these Shared Services may be jointly provided to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC, DEP, and Piedmont is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC, DEP, and Piedmont. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies- of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's, and Piedmont's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC, DEP, and Piedmont incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates (other than the Customer or the Customer's designated representative or agent) shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC, DEP, or Piedmont in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC, DEP, and Piedmont shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy, and the other Affiliates.

2. The books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. If Piedmont supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by either DEC or DEP to generate electricity, DEC or DEP, as applicable, shall file a report with the Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

4. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC, DEP, or Piedmont with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or DEP to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or DEP, as applicable, shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC, DEP, Piedmont, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for Electric Services or Natural Gas Services and non-Electric Services, non-Natural Gas Services, or any combination of such services, from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services and Natural Gas Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC, DEP, and Piedmont shall establish procedures to resolve potential complaints that arise due to the relationship of DEC, DEP, and Piedmont with Duke Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated

representative of DEC, DEP, or Piedmont.

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC, DEP, or Piedmont shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC, DEP, and Piedmont shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1., any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for the EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint with the Commission or otherwise communicate with the Commission or the Public Staff regarding a complaint.

H. Natural Gas/Electricity Competition

DEC, DEP, and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP, and Piedmont shall maintain the following minimum standards:

1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.

2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP, and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement by the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/DEP/PIEDMONT CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/DEP's/Piedmont's Affiliates offer products and services that are separate from the regulated services provided by DEC/DEP/Piedmont. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP/Piedmont to provide any data associated with the Customer account(s) residing in any DEC/DEP/Piedmont files, systems or databases **[or specify types of data]** to the following Affiliate(s) _____. DEC/DEP/Piedmont will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/DEP offers optional, market-based products and services that are separate from the regulated services provided by DEC/DEP. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP to use any data associated with the Customer account(s) residing in any DEC/DEP files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/DEP will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

D. SERVICE AGREEMENT LISTS

Service Agreement lists outlining services that DEC, DEP and Piedmont may receive from their Duke Energy affiliates include the following:

- Service Company Utility Service Agreement List
- Operating Companies Service Agreement List
- Operating Companies/Non-Utility Companies Service Agreement List

For a complete list of the services related to affiliate service agreements, please refer to NCUC Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A or G-9, Sub 682A. These affiliate service agreements may also be found on the State Regulatory Compliance Portal.

In addition, DEC, DEP, and Duke Energy Florida, LLC are parties to the Nuclear Services Agreement, with the Nuclear Services Agreement List, which includes the services that DEC and DEP may receive from each other and Duke Energy Florida, LLC.

E. GUIDELINES FOR TRANSACTIONS BETWEEN DEC/DEP/PIEDMONT AND AFFILIATES

The *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates ("Guidelines")* is an internal document developed to help employees implement the North Carolina Code of Conduct. The Guidelines may be revised from time to time as necessary to meet changing business requirements.

These Guidelines are intended to apply to all employees in dealings between DEC/DEP/Piedmont and their affiliates to assist in compliance with the North Carolina Code of Conduct, North Carolina and South Carolina state laws, and federal laws concerning affiliate transactions. Application of the affiliate rules to specific transactions may depend on the specific facts at issue. Any questions concerning the affiliate rules or these Guidelines should be directed to the subject matter experts listed later in this section.

A. DEFINITIONS

Please reference Section C. *North Carolina Code of Conduct* in this CAM for definitions. Below are some additional definitions used throughout the CAM.

FERC: Federal Energy Regulatory Commission.

NCUC: North Carolina Utilities Commission.

ORS: Office of Regulatory Staff in South Carolina.

PSCSC: Public Service Commission of South Carolina.

Public Items: Items DEC/DEP/Piedmont, in their discretion, make available at no charge to any third party, including an Affiliate, upon request.

Service Company: Duke Energy Business Services LLC ("DEBS"), which is an affiliate that provides shared services to DEC/DEP/Piedmont and their affiliates.

Technology And Trade Secrets: For the purposes of these Guidelines, "Trade Secrets" is defined as information, including a formula, pattern, compilation, device, method, technique, or process, that: (1) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use; and (2) is the subject of efforts that are reasonable under the

circumstances to maintain its secrecy. Technology is scientific, engineering or technical information which is patented or is a trade secret.

B. INFORMATION SHARING RESTRICTIONS

1. Customer Information

- **Customer Information may be disclosed to an Affiliate, Nonpublic Utility Operations, or any third party only with the Customer's prior consent, as described in more detail below.**
  - Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be by written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set out in Attachment A to the Code of Conduct.
  - Departments providing Customer Information to Affiliates or Nonpublic Utility Operations must retain verification of the authorization for the longer of three years or as long as the authorization remains in effect.
  - Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

  Exception: DEC/DEP/Piedmont may disclose Customer Information to Affiliates, Nonpublic Utility Operations or third parties as necessary for the Affiliate, Nonpublic Utility Operations or third party to provide goods or services to DEC, DEP or Piedmont.
  - Affiliates and/or Nonpublic Utility Operations receiving Customer Information under this exception must agree to protect the confidentiality of the Customer Information they receive. Employee training or information technology non-disclosure statements may be used to meet this requirement.
  - Agreements with third parties should provide for the protection of Customer Information.

- Customer Information may be used by DEBS employees to market or sell products or services to customers of DEC/DEP/Piedmont **only** in support of:
  - NCUC or PSCSC approved rate schedules or programs; or
  - Marketing efforts managed and supervised directly by DEC/DEP/Piedmont.

- DEBS employees with access to Customer Information may not act as an improper conduit of this information. For example, employees must not provide indirect access to the data, or recommend action based on the Customer Information, to any DEBS or other Affiliate or Nonpublic Utility Operations employees who have not been granted proper access to the information.

- ***Any improper disclosure of Customer Information requires promptly filing a statement with the NCUC describing the circumstances of the disclosure, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure, and the Legal Department must be informed of the disclosure to facilitate this notification.***

2. Confidential Systems Operation Information

- Confidential Systems Operation Information ("CSOI") may not be disclosed to an Affiliate or Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates at the same time and in the same manner.

- ***Exceptions:***
  - The CSOI is provided to employees of DEC/DEP/Piedmont for the purpose of implementing, and operating pursuant to, the Joint Dispatch Agreement in accordance with the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A.
  - The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.
  - The disclosure is required by law or by a state or federal regulatory agency or court.
  - The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.
  - CSOI may be provided to Utility Affiliates for the purpose of sharing best practices and improving the provision of regulated utility service.
  - The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of information to be disclosed.
  - Sharing of CSOI is permitted if it is otherwise essential to enable DEC/DEP/Piedmont to provide Utility Services to its Customers, or for compliance with the Sarbanes-Oxley Act of 2002.
  - However, certain reporting requirements are triggered by use of this exception. ***Consult with the Legal Department prior to sharing Operation Information under this exception.***
  - Employees receiving CSOI under these exceptions must agree to protect the confidentiality of information they receive and may not improperly share this information with other Affiliate or Nonpublic Utility Operation employees who are not permitted to have access to this information. Employee training or information technology non-disclosure statements may be used to communicate these requirements.
  - DEC/DEP/Piedmont and DEBS's employees with access to CSOI may not act as an improper conduit of this information. For example, employees must not provide indirect access to the data, or recommend action based on the CSOI, to any DEBS or other Affiliate or Nonpublic Utility Operations employees who have not been granted proper access to the information.

- ***Any improper disclosure of CSOI requires promptly filing a statement with the NCUC in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure, and the Legal Department must be informed of the disclosure to facilitate this notification.***

3. Market and Transmission Information

- The FERC Affiliate Restrictions and the Standards of Conduct prohibit the disclosure of DEC/DEP/Piedmont's market information and non-public transmission information to a market-regulated power sales affiliate (otherwise known as a non-regulated affiliate). FERC defines market information as: "non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates." The FERC Standards of Conduct prohibit the disclosure of DEC/DEP/Piedmont's non-public transmission system information to marketing function employees. Information regarding the Standards of Conduct and inappropriate disclosures is explained in Duke Energy's FERC Standards of Conduct Compliance Procedures found at www.ferc.duke-energy.com.
- Any handling or disclosure of DEC/DEP/Piedmont's market information or non-public transmission information by DEBS or its employees which results in (a) a violation of the FERC Affiliate Restrictions or Standards of Conduct, (b) the posting of such data on an OASIS or other Internet website, or (c) other public disclosure of the data, requires that DEC/DEP promptly file a statement with the NCUC. ***The Legal Department must be informed of any such occurrence to facilitate this notification.***

C. AFFILIATE AGREEMENTS

1. Filing Requirements

- Before DEC/DEP/Piedmont may make payment to an Affiliate for services not already approved, it must obtain prior NCUC approval.
- DEC/DEP/Piedmont must file all other affiliate agreements with the NCUC for notice. This notice must be at least 60 days in advance of the transfer of DEC/DEP/Piedmont's technology or trade secrets, provided, however, that DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other.
- Before filing an affiliate agreement with the NCUC, DEC/DEP/Piedmont must submit it, unsigned, to the Public Staff -at least 15 days in advance for informal review.
- DEC/DEP/Piedmont must make available to the ORS copies of affiliate agreements involving payment by DEC/DEP/Piedmont to an Affiliate.
- **Service Level Agreements ("SLA")** may be considered affiliate agreements that trigger these filing and approval requirements. ***Contact the Legal Department before entering into an SLA between DEC/DEP/Piedmont and any Affiliate.***
- DEC/DEP/Piedmont must obtain PSCSC approval prior to the transfer of any utility asset valued at greater than $1 million to any party; and must provide 30 days advance notice to the NCUC prior to the transfer of any utility asset with a gross book value in excess of $10 million to any party.
- Under both North and South Carolina law, DEC/DEP/Piedmont bear the burden of showing that affiliate transactions are reasonable and prudent.

- **Existing Agreements**

- Copies of filed affiliate agreements are available for review on the State Regulatory Compliance Portal.

- On August 26, 2016, DEC, DEP, and Piedmont jointly filed in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A the following affiliate agreements to which they were parties:
  - Service Company Utility Service Agreement
  - Operating Companies Service Agreement
  - Operating Companies/Non-Utility Companies Service Agreement
  - Tax Sharing Agreement
  - Intercompany Asset Transfer Agreement
  - Utility Money Pool Agreement

- DEC and DEP (as well as Duke Energy Florida, LLC) are also parties to the Nuclear Services Agreement, which they jointly filed at the NCUC on December 1, 2011, in Docket Nos. E-2, Sub 998A and E-7, Sub 986A.

- Brief descriptions of these agreements follow:
  - Service Company Utility Service Agreement – It is expected that Franchised Electric & Gas employees whose job responsibilities involve providing certain services to different operating companies will be employed by DEBS and will provide services to DEC/DEP/Piedmont as well as the other Utility Affiliates[1] under this agreement.
  - Operating Companies Service Agreement – Under this agreement, DEC/DEP/Piedmont and their Utility Affiliates may provide certain services to each other. With the exception of DEC/DEP/Piedmont providing services for each other, the Utility Affiliates will request services from each other using Service Request for Affiliates form.
  - Operating Companies/Non-Utility Companies Agreement – Under this agreement, DEC/DEP/Piedmont and their non-utility Affiliates may provide certain services to each other under a Service Request for Affiliates form.
  - Nuclear Services Agreement – Under this agreement, DEC, DEP, and Duke Energy Florida, LLC may provide certain services to each other to support management and operation of the nuclear plants.
  - Tax Sharing Agreement – The Tax Sharing Agreement, which is an agreement for the filing of consolidated income tax returns and for allocation of consolidated income tax liabilities and benefits.
  - Intercompany Asset Transfer Agreement – The Intercompany Asset Transfer Agreement, which is an agreement that allows DEC, DEP, Piedmont and their regulated utility affiliates to transfer assets to one another.
  - Utility Money Pool Agreement – The Utility Money Pool Agreement, which is an agreement that allows the parties to borrow funds on a short-term basis and to

[1] "Utility Affiliates" means the regulated public utility operations of Duke Energy Indiana, LLC, Duke Energy Kentucky, Inc., Duke Energy Florida, LLC, and Duke Energy Ohio, Inc.

create a cash management program.

- Pursuant to North Carolina Regulatory Condition No. 5.4, DEC/DEP/Piedmont filed lists with the NCUC of the services they intend to obtain from their affiliates under the affiliate Service Agreements. Before receiving any services that are not on the appropriate list, DEC/DEP/Piedmont must give the NCUC **15 days advance notice.**

- With the exception of the Nuclear Services Agreement, which was last filed with the NCUC on June 30, 2014, these agreements supersede in their entirety DEC's affiliate service agreements previously filed in Docket Nos. E-7, Sub 795A and E-7, Sub 810; and DEC's and DEP's affiliate service agreements previously filed in Docket Nos. E-7, Sub 986A and E-2, Sub 998A.

- ***Contact the Legal Department before obtaining or providing goods or services from or to an Affiliate that are not covered by Affiliate Agreements.***

D. COST ALLOCATION & TRANSFER PRICING RULES

1. Cost Allocations

- **Corporate Governance and Shared Services**
  - DEC/DEP/Piedmont and their Affiliates may use joint corporate oversight, governance, corporate support and utility support systems and personnel. These services are provided by DEBS under the Service Company Utility Service Agreement (see Affiliate Agreements above).

  - Costs must be allocated or charged back on a fully distributed cost basis and are subject to review by state regulators. Charging methods are described in the applicable Service Agreement.

  - DEC/DEP/Piedmont must perform periodic evaluations that show shared services are cost-beneficial to it on a service by service basis.

- **Joint Purchases**
  - ***Generally:*** DEC/DEP/Piedmont and their Utility Affiliates may capture economies of scale in joint purchases of goods and services (*excluding*: electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement – see special provision below) or the joint development of an asset if (a) the purchase results in cost savings to DEC/DEP/Piedmont's Customers, and (b) the costs are allocated appropriately and an audit trail maintained.

  - ***Coal and Natural Gas:*** DEC/DEP/Piedmont and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas for consumption, if these purchases result in cost savings to DEC/DEP/Piedmont's Customers. All joint

purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's and Piedmont's affiliated transaction reports filed with the Commission.

- ***The Legal Department must be informed of any such transfer to facilitate this notification.***

2. Transfer Pricing Rules

- **Types of Transactions**
  - **Affiliate or Nonpublic Utility Operation Providing Goods or Services to DEC/DEP/Piedmont**
    - Refer to "Filing Requirements" above.
    - DEC/DEP/Piedmont must perform a "make or buy" analysis.
    - For goods and services provided to DEC/DEP/Piedmont by Duke Energy Corporation, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer prices should be the lower of the supplier's fully distributed cost or market value.
    - For goods and services provided to DEC/DEP/Piedmont by each other or another Utility Affiliate, the transfer price should be the supplier's fully distributed cost.
    - Transfer pricing rules apply to Affiliates acting as subcontractors to other Affiliates providing goods or services to DEC/DEP/Piedmont.

  Exceptions:
    - Corporate governance, corporate services and utility support services (discussed above) may be provided at fully distributed cost.

  - **DEC/DEP/Piedmont Providing Utility Services to Affiliates/ Nonpublic Utility Operations**
    - Refer to "Filing Requirements" above.
    - Tariffed services provided by DEC/DEP/Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Utility Services.
    - Untariffed services provided by DEC/DEP/Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation should be transferred at the higher of market value or DEC's, DEP's, or Piedmont's fully distributed cost.
    - Untariffed services provided by DEC/DEP/Piedmont to each other or another Utility Affiliate should be transferred priced at the supplier's fully distributed cost.
    - Loaned Employees
      - DEC/DEP/Piedmont may assign an employee to an Affiliate or Nonpublic Utility Operations if the assignment does not interfere with or impair DEC/DEP/Piedmont's utility responsibilities or business operations.
      - Responsibility for all liabilities to third parties and any legal or other related expenses that arise in connection with the work of the employee lies with the Affiliate.

- **DEC/DEP/Piedmont Providing Goods/Assets to Affiliates/Nonpublic Utility Operations and the transfer or Use of Utility Assets/Goods not subject to Intercompany Asset Transfer Agreement**

  - Tariffed goods provided by DEC/DEP/Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services.
  - All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.
  - All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC/DEP/Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.
  - All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its *Order Approving Stipulation*, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.
  - Untariffed goods provided by DEC/DEP/Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation should be transferred at the higher of market value or DEC/DEP/Piedmont's fully distributed cost.
  - Determining the appropriate price requires consideration of fully distributed cost, market price evaluation and an appropriate allocation methodology (see below).
  - Affiliates/Nonpublic Utility Operations may use DEC/DEP/Piedmont's goods or assets without charge in connection with the performance of work for DEC/DEP/Piedmont if they would permit a third-party supplier to have the same access to such goods or assets without Operations without charge.
  - DEC/DEP/Piedmont may share Public Items with its Affiliates/Nonpublic Utility Operations without charge.
  - No materiality threshold on transfers to/from non-Utility or non-Regulated Utility affiliates.

- ***In each instance, the Legal Department must be contacted prior to any such transfer to facilitate an asset transfer agreement.***

- **Transfer of Technology or Trade Secrets**
  - ***Transfer, including sublicense, of technology or trade secrets by DEC/DEP/Piedmont to an Affiliate requires 60 days prior notice to the NCUC***. Software developed by *or on behalf of* DEC/DEP/Piedmont typically constitutes technology or trade secrets, which may also include proprietary manuals, technical processes, etc. The following procedure should be followed in the event of a request to transfer and provide use of technology or trade secrets to an Affiliate:
    - Notice: The Code of Conduct requires 60-days' notice to the NCUC in advance of the transfer of technology or trade secrets, unless the transfer is between DEC/DEP/Piedmont. If circumstances warrant, DEC/DEP/Piedmont may request a waiver of the advance notice requirement, but the notice period CANNOT be less than 20 business days. The department (or its department financial contact) transferring or allowing use of the DEC/DEP/Piedmont technology or trade secret to an Affiliate must notify the Legal or Carolinas Rates & Regulatory Strategy Departments before the beginning of the advance notice period. Details of the transaction, including description and appropriate compensation support, sufficient to make the filing with the NCUC must be provided in time to meet the notice requirement. If the transferring department requires assistance with determining the pricing methods or other transfer requirements, additional time to consult with the Legal or Carolinas Rates & Regulatory Strategy Departments should be allowed in advance of the notice period.
    - Transfer pricing: Generally, DEC/DEP/Piedmont are compensated for such technology and trade secret transfers at the higher of market or fully-distributed cost, subject to the conditions and/or exceptions discussed in this section. Market and cost comparison procedures to be followed (as well as applicable exceptions) are further discussed in the "Pricing Rules Compliance Documentation – Transfer or Sharing of Goods/Products" section below. The transferring department, along with the department financial contact if necessary, must ensure that the appropriate accounting entries are recorded to compensate DEC/DEP/Piedmont according to the transfer pricing requirements.

      Supporting documentation describing the technology or trade secret transferred, as well as the pricing support documentation must be maintained by the transferring department.

- **Sharing Customer Information or CSOI**
  - Sharing DEC/DEP/Piedmont's Customer Information or CSOI is strictly limited, as described in Sections B.1 & B.2 above. In the event Customer Information or CSOI is provided to an affiliate (or third party other than the Customer or the Customer's designated representative or agent), the North Carolina Code of Conduct requires that all costs incurred in assembling, compiling, preparing, or furnishing the information be recovered from the requesting party.

- "All costs" means fully-distributed cost and includes any overhead or allocable cost associated with the labor cost incurred to provide the information as well as any incremental systems, materials/supplies, or other costs identified with the transaction.

Although the Customer Information or CSOI is specific to DEC/DEP/Piedmont, the employees providing the Customer Information or CSOI, or providing a service using DEC/DEP/Piedmont Customer Information or CSOI, may be utility or Service Company employees. Charging fully distributed cost must have the effect of removing the applicable labor and other dollars from either DEC/DEP/Piedmont direct charges, or from a pool of Service Company dollars, which are otherwise direct charged, distributed, or allocated to DEC/DEP/Piedmont. The following process should be followed to bill or charge costs associated with providing Customer Information or CSOI:

- The department or group providing the Customer Information or CSOI must develop a method to price the transaction or activity (if the activity is recurring) appropriately. For example, a per-transaction price may be developed by observing the average time involved in completing a service using Customer Information, applying a proportionate labor rate plus associated overheads, then multiplying by a number of transactions (tracked or estimated) for the accounting period, to compute a charge to the Affiliate or third party. Less complex methods may be appropriate to charge for one-time or infrequent transactions.
- The department or group providing the Customer Information or CSOI will provide sufficient detail to its department financial contact to enable the contact to make the appropriate journal entry to record the charge (or to bill the third party if applicable). The department financial contact must ensure that the appropriate accounting entries are recorded.
- Supporting documentation describing the transaction, as well as the pricing determination support, must be maintained by the department providing the Customer Information or CSOI or the applicable department.

- **Wholesale Power Sales or Purchases**
  - Require FERC approval.
  - May require Advance Notice to NCUC and approval by State Commissions, depending on the circumstances.

- **Pricing Rules Compliance and Documentation**
  - **Performance of Services**
    - Every DEC/DEP/Piedmont department that performs services for Affiliates should conduct, or cause to be prepared, a periodic market analysis to compare the department's current fully distributed cost to the equivalent market prices. Similarly, when it obtains services from an Affiliate (other than Corporate Governance and Shared Services or under the Utility-to-Utility exception),

each DEC/DEP/Piedmont department should perform, or ensure that the Affiliate performs a market comparison for such services and documents its rationale for selecting the Affiliate.

- **Transfer or Sharing of Goods/Products**
  - DEC/DEP/Piedmont should conduct periodic market to current cost comparisons for utility assets such as facilities, vehicles, equipment and information technology property, which are shared with or used by Affiliates. The market versus cost evaluation is applicable to any such assets provided on an ongoing basis or as the result of an individual transaction. Similarly, when DEC/DEP/Piedmont uses assets owned by an Affiliate, they should perform or ensure that the Affiliate performs a market comparison for such assets.

For the transfer or sharing of items developed, created or constructed by DEC/DEP/Piedmont or an Affiliate (regardless of whether the item is a capital asset), DEC/DEP/Piedmont departments should perform a market comparison to determine the appropriate price, taking into consideration the following as applicable:

- The fully distributed cost to DEC/DEP/Piedmont or the affiliate to develop the item; the appropriate allocation of such costs for items that will be shared, such as software; the market price to purchase the item "off the shelf", if available; and the market price to hire a professional to develop the item.

Exceptions:

- ***No Comparable Market Exception***. If no comparable market exists, the goods or services should be priced at fully distributed costs. A DEC/DEP/Piedmont department relying on this exception should document how it determined that no comparable market exists.

- ***Joint Purchase/Development Exception.*** The Code permits the use of shared corporate governance and shared support and permits joint purchases among DEC/DEP/Piedmont and their affiliates. Therefore, Duke Energy may establish a project to jointly develop an item to be used by multiple business units, including DEC/DEP/Piedmont, provided that the costs are allocated appropriately and accounting records are maintained to reflect the cost sharing. Similarly, DEC/DEP/Piedmont and their affiliates may jointly procure goods or services from third-party suppliers.

- ***Use of Assets in the Performance of Services.*** Affiliates may use DEC/DEP/Piedmont goods or assets without charge in connection with the performance of work for DEC/DEP/Piedmont if DEC/DEP/Piedmont would permit a third-party supplier to have the same access to such goods or assets without charge.

E. REGULATORY OVERSIGHT

- DEC/DEP/Piedmont are required to file a detailed Carolinas CAM and Annual Affiliate Transactions Report with the NCUC. The CAM and Report are subject to regular audit by the Public Staff.
- DEC/DEP/Piedmont are also required to maintain information on affiliate transactions for review by the PSCSC and ORS upon request.
- Corporate Audit Services performs an annual audit of Affiliate transactions.
- Independent audit of transactions under the Service Agreements occurs no less than every 2 years.

F. COMPLAINT PROCEDURE

The Code of Conduct requires DEC/DEP/Piedmont to follow established procedures to resolve any complaints that may arise due to the relationship of DEC/DEP/Piedmont with Duke Energy Corporation, its other Affiliates, or its Nonpublic Utility Operations. Complaints could originate from any source, including customers, potential suppliers, alliance partners, competitors, etc., or could be referred to DEC/DEP/Piedmont by the NCUC, PSCSC, Public Staff, or ORS. The following steps comprise the procedure to follow in the event of a complaint:

- Any verbal or written complaints will be referred to the Duke Energy Regulatory Affairs contact below (written complaints forwarded by the NCUC, PSCSC, Public Staff or ORS are automatically received by the Regulatory Affairs team).
- The Regulatory Affairs team will provide written notice to the complainant within 15 days indicating that the complaint was received.
- The Regulatory Affairs team will conduct or coordinate the investigation of the complaint, provide the results of such investigation to the Legal Department for review and input, and report back the status or results of the review to the complainant within 60 days of receiving the complaint.
- A log of complaints received and the related documents will be maintained by the Regulatory Affairs team for audit purposes.

Note: Any complaints received via the Ethics Line will be handled separately according to the procedures established for Ethics Line.

SUBJECT MATTER EXPERTS & RESOURCES

Name	Area	Phone
Kendrick Fentress	Legal – NC State Rules	919.546.6733
Rebecca Dulin	Legal – SC State Rules	803.988.7130
Ann Warren	Legal – FERC Rules	704.382.2108
Alan Hutcherson	Corporate Compliance – State Rules	704.382.5667
Chris Whicker	Corporate Compliance – FERC Rules	704.382.2869
Laura Bateman	DEC and DEP Rates & Regulatory	919.546.3324
Pia Powers	Piedmont Rates & Regulatory	704.731.4259

Note: Department financial contacts referred to in the guidelines above are in the Financial Planning and Analysis organization.

F. SHARED SERVICES COST DISTRIBUTION PROCESS

Services designated as "shared support," for purposes of the North Carolina Regulatory Conditions and Code of Conduct, are Services that are corporate or general utility in nature and are used by multiple business units. These services are provided pursuant to a Utility Service Agreement filed with the NCUC.

The list of services conforms to the service category descriptions included in Attachment 2 of the Service Company Utility Service Agreement, and represents the shared services offered that DEC, DEP, and Piedmont intend to obtain under this agreement. DEC, DEP, and Piedmont are required by the North Carolinas Utilities Commission to update the list of services as necessary. Interim changes to this list require filing with the Commission, with 15 days advance notice of the proposed changes.

The shared services cost distribution process is the method by which costs of the Services Company are fully distributed.

The objectives of the cost distribution process are to:

- Meet regulatory requirements.
- Ensure that each affiliate shares in and is appropriately charged for the relevant shared services costs.
- Assist affiliates in understanding the cost drivers and basis for allocation of shared services costs that affect their operating results.
- Provide an accounting model whereby affiliates can see how much is allocated to them for each shared service.

Costs for shared services are distributed to affiliates within Duke Energy through *(i)* direct charges, *(ii)* distribution or *(iii)* allocation. Costs are direct charged to the extent possible. Costs that cannot be direct charged can be distributed to the applicable business units using specific percentages if known. Costs that cannot be direct charged or distributed are allocated to the business units receiving the benefit using reasonable allocation methods as described in the "Shared Services Cost Distribution Details" section of this manual. Services are charged to

Affiliates on a fully distributed cost basis and include labor and non-labor costs. As part of a fully distributed cost, an overhead component is charged to Affiliates as a percentage of Service Company labor costs, whether direct charged, distributed or allocated. This overhead represents the cost of shared services provided by shared services employees.

The Corporate Accounting group is responsible for developing the following allocation factors, which serve as the basis for the allocation of costs that have not been direct charged or distributed. Final allocation factors distributing costs to each affiliate sum to 100% for each cost pool, thus clearing out 100% of costs to be allocated each month. Interim adjustments to allocation factors are made only for material transactions, such as an acquisition or divestiture of an affiliate, and for major company reorganizations.

Corporate Accounting reviews Service Company allocation factors annually. Typically during the budget process, rates are recalculated and implemented for actuals at the beginning of the following year. These rates are reflected in the Service Company allocation rate schedule included in the Cost Allocation Manual.

The Service Company also charges for certain services under the Service Company Utility Service Agreement. Types of pass-through costs typically handled by the Service Company may include:

1. Finance & Accounting Services
2. Insurance Premium Expense
3. Advertising Expense
4. Community Relations Projects
5. Donations
6. Employee Benefits Expense
7. Dues / Subscriptions
8. Merger Execution Costs
9. Research & Development
10. Miscellaneous Lease / Rent Expense

G. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH THE SERVICE COMPANY

On a regular basis, Service Company employees provide support to DEC/DEP/Piedmont. All Service Company resources used to support DEC/DEP/Piedmont must properly charge the respective utility through *(i)* direct charges, *(ii)* distribution or *(iii)* allocation. Charging fully distributed cost to DEC/DEP/Piedmont is normally accomplished with the application of a percentage loaded on direct labor. Service Company management is accountable for employees appropriately charging their costs. An Affiliate Rules and Transactions Computer Based Training ("CBT") (emphasis on DEC/DEP/Piedmont) is available in the Training Connection on the Portal.

The following procedure addresses employees' and management's responsibilities.

A. General Guidelines

1. Consistent with Regulatory Condition No. 5.5, hours worked by Service Company employees in direct support of DEC/DEP/Piedmont are charged directly to the respective utility to the maximum extent practicable.
2. First-line supervisors should review and approve, when appropriate, source documentation resulting in a charge by Service Company to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to DEC/DEP/Piedmont.
4. Service Company to DEC/DEP/Piedmont transactions are covered under the Service Company Utility Agreement.

B. Time Reporting

When a Service Company employee provides direct support to DEC/DEP/Piedmont: Consistent with Regulatory Condition No. 5.5, hours worked by Service Company employees in direct support of DEC/DEP/Piedmont are charged directly to the respective utility to the maximum extent practicable.

1. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for paid supplemental compensation.
2. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads of fringe benefits, payroll taxes, incentive pay and unproductive time, as applicable.

C. Labor Allocations

Service Company employees provide services to DEC/DEP/Piedmont at fully distributed cost. Allocation of costs described in items 1 through 5 below are applied as a cost factor to labor charged to DEC/DEP/Piedmont. Below are the various cost components of labor loads. The rates for these items may be adjusted during the year to properly accrue the associated actual or anticipated cost.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement, and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among Affiliates.

2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among Affiliates.

3. Incentive Allocation

Incentives are accrued via a loading factor applied to labor charges.

4. Unproductive Cost Allocation

An unproductive cost allocation is applied to productive labor charges by the Service Company employee. Service Company allocates unproductive costs pro rata to productive labor, either via a monthly ratio or standard rates.

5. Service Company Overhead

A Service Company overhead rate is based on historical enterprise and governance overhead charged to Regulated Utilities in the following functions: Information Systems, Transportation, Human Resources, Materials Management, Accounting, Public Affairs, Legal, Finance, Facilities, Internal Auditing, Environmental, Health and Safety, Investor Relations, Planning, and Executive.

H. SHARED SERVICES COST DISTRIBUTION DETAILS

See the following charts for descriptions of services provided and associated allocation methods and factors

2020 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Information Systems	Development and support of mainframe computer software applications.	Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second	ENMF	Information Systems	Mainframe Svcs Ent	ENTCPUMFR	S05	67.70	-	-	12.09	2.06	10.41	-	92.26
			PRMF	Information Systems	Mainframe Svcs Ent PE	PRECPUMFR	P05	-	57.54	42.46	-	-	-	-	100.00
			DEMF	Information Systems	Mainframe Svcs Ent DUK	DENTCPUMFR	D05	45.68	15.87	11.71	8.15	1.39	7.02	-	89.82
			PUMF	Information Systems	Mainframe Svcs Utility PE	PRUCPUMFR	P11	-	57.54	42.46	-	-	-	-	100.00
	Procurement and support of personal computers and related network and software applications.	No. of Personal Computer Workstations Ratio	ENWS	Information Systems	Worksta Svcs Enterprise	ENTWKSWKS	S06	83.70	-	-	7.72	0.54	2.37	-	94.33
			PRWS	Information Systems	Worksta Svcs Enterprise PE	PREWKSWKS	P06	-	65.65	32.96	-	-	-	-	98.61
			DWSE	Information Systems	Worksta Svcs Enterprise DUK	DENTWKSWKS	D06	42.33	29.85	15.00	3.89	0.27	1.21	-	92.55
			PUWS	Information Systems	Worksta Svcs Utility PE	PRUWKSWKS	P12	-	65.65	32.96	-	-	-	-	98.61
	Development and support of distributed computer software applications (e.g., servers).	Number of Info Systems Servers Ratio	ENSS	Information Systems	Server Svcs Enterprise	ENTSYSSVR	S07	53.57	-	-	22.90	3.56	9.41	-	89.44
			PRSS	Information Systems	Server Svcs Enterprise PE	PRESYSSVR	P07	-	45.20	53.13	-	-	-	-	98.33
			DESS	Information Systems	Server Svcs Enterprise DUK	DENTSYSSVR	D07	28.27	16.93	19.90	12.10	1.88	4.97	-	84.05
			UTSS	Information Systems	Server Svcs Utility	UTISYSSVR	S13	28.60	17.13	20.13	12.25	1.90	5.01	-	85.02
			PUSS	Information Systems	Server Svcs Utility PE	PRUSYSSVR	P13	-	45.20	53.13	-	-	-	-	98.33
	Installation and operation of communications systems.	Number of Employees Ratio	ENTS	Information Systems	Telecom Svcs Enterprise	ENTEMPTEL	S33	75.32	-	-	13.62	1.00	3.58	-	93.52
			PRTS	Information Systems	Telecom Svcs Enterprise PE	PREEMPTEL	P33	-	62.29	36.28	-	-	-	-	98.57
			DETS	Information Systems	Telecom Svcs Enterprise DUK	DENTEMPTEL	D33	37.44	26.42	15.37	6.76	0.48	1.78	-	88.25
			DUTS	Information Systems	Telecom Svcs Utility	DUTEMPTEL	D34	38.09	26.88	15.64	6.91	0.52	1.83	-	89.87
			UTTS	Information Systems	Telecom Svcs Utility	UTIEMPTEL	S34	78.16	-	-	14.14	1.02	3.72	-	97.04
			PTSU	Information Systems	Telecom Svcs Utility PE	PRUEMPTEL	P34	-	62.29	36.28	-	-	-	-	98.57
			ENHD	Information Systems	Helpdesk Services	ENTEMPHLP	S33	75.32	-	-	13.62	1.00	3.58	-	93.52
			DEHD	Information Systems	Helpdesk Services DUK	DENTEMPHLP	D33	37.44	26.42	15.37	6.76	0.48	1.78	-	88.25
			PRHD	Information Systems	helpdesk Services PE	PREEMPHLP	P33	-	62.29	36.28	-	-	-	-	98.57
	Information systems management and support services.	No. of Personal Computer Workstations Ratio	ENMA	Information Systems	ITS Mgt & Apps Svcs Ent	ENTIMFITM	S35	42.33	29.85	15.00	3.89	0.27	1.21	-	92.55
			DEMA	Information Systems	ITS Mgt & Apps Svcs Ent DE	DENTIMFITM	D35	42.33	29.85	15.00	3.89	0.27	1.21	-	92.55
			PRMA	Information Systems	ITS Mgt & Apps Svcs Ent PE	PREIMFITM	P35	42.33	29.85	15.00	3.89	0.27	1.21	-	92.55
			UTMA	Information Systems	ITS Mgt & Apps Utility	UTIIMFITM	S36	86.79	-	-	8.00	0.56	2.45	-	97.80
			DELH	Information Systems	Duke Energy Lighthouse	DUWKSITM	D11	43.12	30.39	15.28	3.98	0.27	1.23	-	94.27
			DUMA	Information Systems	ITS Mgt & Apps Svcs Util DE	DUTIMFITM	D36	42.33	29.85	15.00	3.89	0.27	1.21	-	92.55

2020 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Meters	Procures, tests and maintains meters.	*Number of Customers Ratio*	DEMS	Meters	Meter Svcs Utility DE	DUTILSMTR	D14	28.48	17.05	18.86	8.99	1.53	7.74	-	82.65
			UMMS	Meters	Meter Svcs Util MWonly Elec/Gas	UTMCLSMTR	SE0	-	-	-	37.42	6.39	32.22	-	76.03
			UEMS	Meters	Meter Svcs Util MW Elec	UTELSMTR	SE8	-	-	-	49.22	8.40	42.38	-	100.00
Transportation	Procures and maintains vehicles and equipment.	*Number of Employees Ratio*	DUVE	Transportation	Transp Vehicles Utility DE	DUTIBMPVEH	D10	38.52	27.16	15.99	7.05	0.72	1.53	-	90.97
			UMVE	Transportation	Transp Vehicles Util MW only	UTMBMPVEH	SE5	-	-	-	68.76	7.05	14.89	-	90.70
	Procures and maintains aircraft and equipment.	*Three Factor Formula*	DGAV	Transportation	Transp Aviation Gvnce	DGOVSRAVI	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
								-	-	-	-	-	-	-	-
			DEAV	Transportation	Transp Aviation Svcs Ent DE	DENTSRAVI	D03	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission systems	*Circuit Miles of Electric Transm Lines Ratio*	UTTR	Electric System Maintenance	ESS Elec Tran Utility	UTIOMETR	SE5	41.66	19.97	15.61	16.85	0.34	5.57	-	100.00
			UMTR	Electric System Maintenance	ESS Elec Tran Utility - MW	UTIOMEMW	SE6	-	-	-	74.03	1.50	24.47	-	100.00
	Services related to distribution systems	*Circuit Miles of Electric Dist. Lines Ratio*	UTDI	Electric System Maintenance	ESS Elec Dist Utility	UTIOMEDT	SE6	39.77	25.92	15.39	11.48	1.11	6.33	-	100.00
			UMDI	Electric System Maintenance	ESS Elec Dist Utility MW only	UTMOMEDT	SE7	-	-	-	60.67	5.86	33.47	-	100.00
Marketing and Customer Relations Grid Solutions	Advises the Client Companies in relations with domestic utility customers. Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*						-	-	-	-	-	-	-	-
			PUBD	Marketing and Customer Relations	M&CR SALES & Demand Util PE	PRUTSALMCR	PL7	-	47.49	52.51	-	-	-	-	100.00
			NET	Marketing and Customer Relations	Customer Strategy R&S	UTISALNET	SY5	60.92	-	-	19.24	3.28	16.56	-	100.00
			STD	Marketing and Customer Relations	Standard Services	UTISALSTD	SE7	54.24	-	-	17.13	2.92	14.74	-	89.03
			MSST	Marketing and Customer Relations	Mkt Sol - SrvGp Duke Standard	UTMSOLSTD	D98	60.92	-	-	19.24	3.28	16.56	-	100.00
			UMSD	Marketing and Customer Relations	M&CR Standard Prod Util MWonly	UTMSALNET	SE8	-	-	-	37.42	6.39	32.22	-	76.03
			UMNT	Marketing and Customer Relations	M&CR Net Product Util MW only	UTMSALSTD	SE8	-	-	-	37.42	6.39	32.22	-	76.03
			UESD	Marketing and Customer Relations	M&CR Std&Dmnd Util MWElec only	UTMSALMCR	SE6	-	-	-	49.22	8.40	42.38	-	100.00
			UGSD	Marketing and Customer Relations	M&CRSale&Demand Util MWGas only	UTGSALMCR	SE7	-	-	-	-	-	-	-	-
			DTNT	Marketing and Customer Relations	M&CR Elec Only Util DE	DUTIOLMCR	D75	34.43	20.64	22.82	10.88	1.86	9.37	-	100.00
			UTNT	Marketing and Customer Relations	M&CRSale&Demand Uti MWGas only	UTISANET	SY5	60.92	-	-	19.24	3.28	16.56	-	100.00
	Advises the Client Companies in relations with domestic utility customers. Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	UTMR	Marketing and Customer Relations	M&CR Mtr Rdg&Pmt Proc Util	UTIOLSPMT	SI7	54.24	-	-	17.13	2.92	14.74	-	89.03
			DUMR	Marketing and Customer Relations	M&CR Customers Util ND	DUTIOLSPMT	D37	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			DUMS	Marketing and Customer Relations	Mkt Sol Svco Utilities Std	DUTIOLSPAY	D95	34.43	20.64	22.82	10.88	1.86	9.37	-	100.00
			UMMR	Marketing and Customer Relations	M&CR Mtr Rdg&PmtPrc Util MWonly	UTMCLSPMT	SE0	-	-	-	37.42	6.39	32.22	-	76.03
			UOMR	Marketing and Customer Relations	M&CR Mtr Rdg Pmt Prc DEO DEK only	UTOCLSPMT	SE9	-	-	-	-	10.21	51.48	-	61.69
			DCTH	Marketing and Customer Relations	M&CR Customers Util ND	DGOVCUSCT A	DCS	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48

2020 SERVICE COMPANY COST ALLOCATION DETAILS

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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Marketing and Customer Relations Grid Solutions	Advises the Client Companies in relations with domestic utility customers. Customer services including the operation of call center.	*Number of Customers Ratio*	UEMR	Marketing and Customer Relations	M&CR McRdg&PrmPrc Util MWBec	UTEDLSPMT	S58	-	-	-	49.22	8.40	42.38	-	100.00
			UMPD	Marketing and Customer Relations	M&CR Util MW PD	UTMOLSMPD	S59	-	-	-	37.42	6.39	32.22	-	76.03
			DCIS	Marketing and Customer Relations	M&CR Cust. Info Sys_Util	DUTICLSSYS	T05	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			UWPD	Marketing and Customer Relations	M&CR PD DEO/DEK E/G	UTMOLSWPD	S70	-	-	-	-	10.21	51.48	-	61.69
	Advises the Client Companies in relations with domestic utility customers. Costs associated with Smart Grid activities	*Number of Customers Ratio*	USGA	Marketing and Customer Relations	M&CR Smart Grid All E/G	UTICLSSG	S76	54.24	-	-	17.13	2.92	14.74	-	89.03
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only	UTEDLSSG	S77	60.92	-	-	19.24	3.28	16.56	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G	DUTICLSSG	D89	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only	DUTEDLSSG	D93	34.44	20.64	22.81	10.88	1.86	9.37	-	100.00
			UTSS	Marketing and Customer Relations	Non-Smart Grid SES O&M	UTICLSSES	S84	54.24	-	-	17.13	2.92	14.74	-	89.03
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC E/G	PUTICLSSG	P91	-	47.49	52.51	-	-	-	-	100.00
			USGA	Marketing and Customer Relations	M&CR Smart Grid Util Capital	UTICLSSG	S80	54.24	-	-	17.13	2.92	14.74	-	89.03
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only Capital	UTEDLSSG	S81	60.92	-	-	19.24	3.28	16.56	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G-Capital	DUTICLSSG	D90	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only - Capital	DUTEDLSSG	D94	34.44	20.64	22.81	10.88	1.86	9.37	-	100.00
			UTSS	Marketing and Customer Relations	Non-Smart Grid SES Cap	UTICLSSES	S85	54.24	-	-	17.13	2.92	14.74	-	89.03
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC E/G - Capital	PUTICLSSG	P92	-	47.49	52.51	-	-	-	-	100.00
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G	DUTICLSGS	T01	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G - Capital	DUTICLSGS	T02	32.19	19.29	21.33	10.17	1.74	8.76	-	93.48
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric	DUTEDLSGS	T03	34.43	20.64	22.82	10.88	1.86	9.37	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric - Capital	DUTEDLSGS	T04	34.43	20.64	22.82	10.88	1.86	9.37	-	100.00
Electric Transmission & Distribution Engineering & Construction - Designs and monitors construction of electric transmission and distribution lines and substations. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.	Transmission engineering and construction:	*(Electric Transmission Plant$) Construction-Expenditures Ratio*	UTET	Electric Transmission & Distribution	Eng & Constr ET Utility	UTICONETR	S18	22.62	15.41	38.32	12.45	2.11	9.09	-	100.00
			UEET	Electric Transmission & Distribution	Eng & Constr ET Util MW only	UTMOCONETR	S62	-	-	-	52.63	8.93	38.44	-	100.00
								-	-	-	-	-	-	-	-
	Distribution engineering and construction:	*(Electric Distribution Plant$) Construction-Expenditures Ratio*	UTED	Electric Transmission & Distribution	Eng & Constr ED Utility	UTICONEDT	S10	33.01	23.33	21.08	11.54	2.08	8.96	-	100.00
			UEED	Electric Transmission & Distribution	Eng & Constr ED Util MW only	UTMOCONEDT	S61	-	-	-	51.12	9.22	39.66	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-

2020 SERVICE COMPANY COST ALLOCATION DETAILS
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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Power Engineering & Construction	Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	*(Electric Production Plant+) Construction - Expenditures Ratio*	UTEC	Power Engineering & Construction	Eng & Constr Pwr Prod Util	UTICONPWR	S25	41.35	20.09	15.94	20.11	2.51	-	-	100.00
			UJEC	Power Engineering & Construction	Eng&Constr Pwr Prod Utl MWonly	UTMCONPWR	S53	-	-	-	88.89	11.11	-	-	100.00
			UGEG	Power Engineering & Construction	Eng & Constr Gas Util MW only	UTMCONGAS	S64	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Human Resources	Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments. Supervises contract negotiations and relations with labor unions.	*Number of Employees Ratio*	DGHR	Human Resources	HR Svcs Gvrnce	DGOVEMPHRS	D02	37.83	26.67	15.70	6.93	0.71	1.50	-	89.34
			DHRE	Human Resources	HR Services Enterprise DE	DENTEMPHRS	D04	37.83	26.67	15.70	6.93	0.71	1.50	-	89.34
			UTHR	Human Resources	HR Services Utility	UTIEMPHRS	S38	38.52	27.16	15.99	7.05	0.72	1.53	-	90.97
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Supply Chain - Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.	Procurement of materials and contract services and vendor payment processing:	*Procurement Spending Ratio*						-	-	-	-	-	-	-	-
			DUSC	Materials Management	Mat'ls Mgmt Sply Chn Util DE	DUTIPROSPC	D19	32.98	24.41	16.92	8.83	1.84	4.22	0.02	89.00
			DESC	Materials Management	Mat'ls Mgmt Sply Chain Ent DE	DENTPROSPC	D08	31.95	23.74	16.40	8.56	1.58	4.09	0.02	88.34
			UPPD	Materials Management	MW ELEC/GAS DELIVRY STOREROOM	UTIPROSMM	S72	-	-	-	-	7.01	77.50	-	84.51
	Management of materials and supplies inventory:	*Inventory Ratio*	UTIN	Materials Management	Mat'ls Mgmt Inventory Util	UTIINVSPC	S20	16.78	25.76	28.75	16.14	0.13	12.44	-	100.00
								-	-	-	-	-	-	-	-
Facilities	Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.	*Square Footage Ratio*	GORE	Facilities	RE Facility Svcs CLT GO	CLTSQFFAC	S27	57.86	40.79	0.89	0.34	-	-	-	99.88
			ONRE	Facilities	RE Fac Svcs - Cincinnati	CINSQFFAC	S50	24.22	17.07	1.57	5.72	-	8.20	-	56.78
			PLRE	Facilities	RE Fac Svcs - Plainfield	PLDSQFFAC	S51	15.42	10.87	0.53	70.85	-	-	-	97.67
			MWRE	Facilities	RE Facility Services MW Utility	UTMSQFFAC	S71	-	-	-	65.80	3.57	17.52	-	86.89
			DERE	Facilities	RE Facility Services Ent DE	DENTFFFAC	D39	40.12	28.28	17.60	3.93	-	0.26	-	90.19
Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	*Three Factor Formula*	DGAC	Accounting	Accounting Gvrnce	DGOV3FFACT	D01	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DGVP	Accounting	VSP - Governance DE	DGOV3FFVSP	D03	36.31	24.96	17.62	10.89	1.23	3.67	0.02	94.70
			PGVP	Accounting	VSP - Governance	PRGV3FFVSP	P03	-	58.50	41.50	-	-	-	-	100.00
			DEAC	Accounting	Accounting Svcs Ent DE	DENT3FFACT	D03	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
			UTAC	Accounting	Acctg Svcs Utility	UTI3FFACT	S09	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05
			UMAC	Accounting	Acctg Svcs Util NW REBGonly	UTM3FFACT	S53	-	-	-	61.86	6.90	20.14	-	88.90
			DDEP	Accounting	DEBS Depreciation DE	DENT3FFDEP	D49	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
			PRDP	Accounting	SvcCo Depreciation PE	PRES3FFDEPR	P49	-	58.50	41.50	-	-	-	-	100.00

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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd DGH	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	Three Factor Formula	DGDC	Accounting	Governance CT A Depreciation DE	DGOV3FDDEP	DGH	36.31	24.96	17.62	10.89	1.23	3.67	0.02	94.70
			DCTG	Accounting	CT A Governance DE	DGOV3FRDTA	DGB	36.31	24.96	17.62	10.89	1.23	3.67	0.02	94.70
			PNVG	Accounting	Piedmont CT A Gov	GOV3FRDTAP	DGF	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			PNGG	Accounting	Piedmont CT A Gov - Gas Only	GOV3FRDTAPG	DGE	-	-	-	-	-	-	-	-
			PLDC	Accounting	Governance CT A Depreciation PE	PRV3FRDEPP	PGH	-	58.50	41.50	-	-	-	-	100.00
			GSAC	Accounting	Accounting Gas Only	UTI3FRGACT	GD3	-	-	-	-	-	-	-	-
		Generating Unit MW Capability Ratio (MDC)	DPNL	Accounting	Duke Progress CT A Nuclear	DGOV3FRDAN	CG3	67.00	33.00	-	-	-	-	-	100.00
	Rate of Return - Allocates the Service Company's portion of the utilities chargeback for affiliate use of space.	Three Factor Formula	DURR	Facilities Rate of Return Allocation	Facilities ROR Gurnee DE	DGOVERPROR	CG4	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
Power Planning and Operations - Coordinates the planning, management and operation of Duke Energy Corporation's electric power systems including additions and retirements to Duke Energy Corporation's electric generation, transmission and distribution systems.	Generation planning:	Ber Peak Load Ratio						-	-	-	-	-	-	-	-
			DUGE	Power Planning and Ops	Pwr Plng&Ops Gen Plng Util ND	DUTIPKLGPL	D21	38.18	28.06	19.60	12.44	1.72	-	-	100.00
	Transmission planning:	Ber Peak Load Ratio						-	-	-	-	-	-	-	-
			DUTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util ND	DUTIPKLETR	D32	37.85	22.67	19.10	12.12	1.32	6.94	-	100.00
	Distribution planning:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Ber Peak Load Ratio						-	-	-	-	-	-	-	-
			DUDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util ND	DUTIOMEDL	D41	38.81	24.29	17.25	11.80	1.21	6.64	-	100.00
								-	-	-	-	-	-	-	-
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	Sales Ratio	UTGD	Power Planning and Ops	Pwr Plng&Ops Gen Dspch Util	UTISALGDP	S42	27.93	23.25	26.36	20.40	2.06	-	-	100.00
								-	-	-	-	-	-	-	-
	Transmission Operations:	Weighted Average of the Circ Miles of Elec Transm Lines Ratio and the Ber Peak Load Ratio	UTTO	Power Planning and Ops	Pwr Plng&Ops Trans Ops Util	UTIOMOTR	S31	39.78	21.31	17.35	14.48	0.83	6.25	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Distribution Operations:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Ber Peak Load Ratio	UTDO	Power Planning and Ops	Pwr Plng & Ops Dist Ops Util	UTIOMDDL	S22	38.81	24.29	17.25	11.80	1.21	6.64	-	100.00
								-	-	-	-	-	-	-	-
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.	Generating Unit MW Capability /MDC Ratio						-	-	-	-	-	-	-	-
			REPO	Power Planning and Ops	Pwr Plng & Ops Pwr Ops Reg	REGOAPOP	S28	30.01	23.93	26.03	17.24	2.79	-	-	100.00
			RCLO	Power Planning and Ops	Reg Coal - All Juris (DEBS)	RCLOAPOP	D99	38.08	19.54	13.42	25.70	3.26	-	-	100.00
			RCTO	Power Planning and Ops	Reg CT/CC - All Juris (DEBS)	RCTOAPOP	S98	23.69	27.38	35.95	10.56	2.42	-	-	100.00
			RMVO	Power Planning and Ops	Reg Coal/CT - Midwest (DEBS)	REGMOPOP	S99	-	-	-	86.07	13.93	-	-	100.00

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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Public Affairs	Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction, lithography, photography and video services.	*Three Factor Formula*	DGPA	Public Affairs	Pub Affs Gvrnce	DGOV3FRPAF	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DGPP	Public Affairs	Public Policy Gvrnce	DGOV3FRPPO	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DEPA	Public Affairs	Public Affairs Services Ent DE	DENT3FRPAF	D03	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
	Utility Specific Activities	Weighted Average of # of *Customers Ratio* and # of *Employees Ratio*	UTPA	Public Affairs	Public Affairs Services Utilit	UTILOSPAF	S24	33.49	22.10	17.42	8.02	1.13	4.64	-	86.80
								-	-	-	-	-	-	-	-
Legal	Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.	*Three Factor Formula*	DLEE	Legal	Legal Governance	DGOV3FRLEG	CGI	63.55	-	-	18.88	2.13	6.33	0.03	90.92
			ENLE	Legal	Legal Governance	GOV3FRLEG	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			PGLG	Legal	Legal Governance PE	PRGV3FRLEG	PGI	-	58.50	41.50	-	-	-	-	100.00
			UTLE	Legal	Legal Services Utility	UTI3FRLEG	S09	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05
Rates	Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers usage.	*Sales Ratio*	UTRA	Rates	Rates Utility	UTISALRAT	S44	28.68	20.29	13.19	10.09	1.31	6.58	-	80.14
			UORA	Rates	Rates Svcs Util DEO DEK only	UTOSALRAT	S55	-	-	-	-	9.45	52.28	-	61.73
			UMRA	Rates	Rates DEO & DEK Reg	UTMSALRAT	S86	-	-	-	-	7.63	38.18	-	45.81
Finance	Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.	*Three Factor Formula*	DGFI	Finance	Financial Svcs Gvrnce	DGOV3FRFIN	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DEFI	Finance	Financial Svcs DE	DENT3FRFIN	D03	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
			UTFI	Finance	Financial Services Utility	UTI3FRFIN	S09	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05
			UMFI	Finance	Financial Svc Util MW REGonly	UTMBFRFIN	S53	-	-	-	61.86	6.90	20.14	-	88.90
Rights of Way - Purchases, surveys, records, and sells real estate interests for Client Companies.	Services related to electric distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	DURD	Rights of Way	Right of Way ED Sys Util ND	DUTIOMRWD	D87	39.77	25.92	15.39	11.48	1.11	6.33	-	100.00
	Services related to electric generation system:	*Ele. Peak Load Ratio*	DURG	Rights of Way	Right of Way Gen Sys Util ND	DUTIPKLRWG	D88	38.18	28.06	19.60	12.44	1.72	-	-	100.00
	Services related to electric transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	DURW	Rights of Way	Right of Way ET Sys Util ND	DUTIOMROW	D45	41.66	19.97	15.61	16.85	0.34	5.57	-	100.00
								-	-	-	-	-	-	-	-
Internal Auditing	Reviews internal controls and procedures to ensure that assets are safeguarded & that transactions are properly authorized & recorded.	*Three Factor Formula*	DGIA	Internal Auditing	Internal Audit Gvrnce	DGOV3FRIAU	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DUIA	Internal Auditing	Intrnl Audit Svcs Utility DE	DUTI3FRIAU	D09	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05

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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	DEI Total	DEK Total	DEO Total	Total Comm Trans-Elec	Total Electric Utilities
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Three Factor Formula*	DGEA	Environmental, Health and Safety	Envir Affs Gvrnce	DGOV3FRBV	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
								-	-	-	-	-	-	-	-
			BNEA	Environmental, Health and Safety	Enviro Affairs Svcs Ent	ENT3FRBV	SI6	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
	Utility Specific Activities	*Sales Ratio*	UTEA	Environmental, Health and Safety	Enviro Affairs Svcs Utility	UTISALBV	SI7	28.68	20.29	13.19	10.09	1.31	6.58	-	80.14
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	UTRU	Fuels	Fuels Utility	UTISALFUE	SI8	27.93	23.25	26.36	20.40	2.06	-	-	100.00
								-	-	-	-	-	-	-	-
Investor Relations	Provides communications to investors and the financial community, performs transfer agent and shareholder record keeping functions, administers stock plans and performs stock-related regulatory reporting.	*Three Factor Formula*	DGIR	Investor Relations	Investor Rel Gvrnce	DGOV3FINV	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
								-	-	-	-	-	-	-	-
Planning	Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.	*Three Factor Formula*	DGPS	Planning	Planning Svcs Gvrnce	DGOV3FRLN	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DGCD	Planning	Corp Dvlpmnt Gvrnce	DGOV3FRDO	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			DEPS	Planning	Planning Svcs Enterprise DE	DENT3FRLN	D03	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
			DUPS	Planning	Planning Svcs Utility DE	DUT3FRLN	D09	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05
Executive	Provides general administrative and executive management services.	*Three Factor Formula*	DGEX	Executive	Exec Governance	DGOV3FREXC	DGI	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			ENEX	Executive	Exec Services Enterprise	ENT3FREXC	SI3	34.26	23.53	16.62	10.27	1.16	3.46	0.02	89.32
			UTEX	Executive	Exec Services Utility	UTI3FREXC	SI9	35.28	24.24	17.13	10.61	1.20	3.57	0.02	92.05
			UMEX	Executive	Executive Svc Util MW REG only	UTM3FREXC	SI3	-	-	-	61.86	6.90	20.14	-	88.90
			UOEX	Executive	Exec Svcs Utility DEO DEK only	UTO8FREXC	SI6	-	-	-	-	18.24	52.76	-	71.00
			DGSC	Executive	Stock Comp Legacy DE	GOV3FRSTK	CG1	63.55	-	-	18.88	2.13	6.33	0.03	90.92
			DGEP	Executive	ESP Other Governance	DGOV3FREEP	DG7	34.25	23.53	16.62	10.27	1.16	3.46	0.02	89.31
			PSTK	Executive	Stock Comp Legacy PGN	PRGV3FRSTK	PG1	-	58.50	41.50	-	-	-	-	100.00
Interest	Allocates Interest		DEAI	Interest	Accrg Interest Svc Enterprise DE	DENTINTACT	DS2	34.54	19.64	11.54	14.18	2.79	7.57	0.02	90.28

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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Information Systems	Development and support of mainframe computer software applications.	*Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second*	BNMF	Information Systems	Mainframe Svcs Ent	ENTCPUMFR	S05	-	1.45	6.29	-	7.74	-	-	100.00
			PRMF	Information Systems	Mainframe Svcs Ent PE	PRECPUMFR	P05	-	-	-	-	-	-	-	100.00
			DEMF	Information Systems	Mainframe Svcs Ent DUK	DENTCPUMFR	D05	4.95	0.98	4.25	-	10.18	-	-	100.00
			PUMF	Information Systems	Mainframe Svcs Utility PE	PRUCPUMFR	P11	-	-	-	-	-	-	-	100.00
	Procurement and support of personal computers and related network and software applications.	*No. of Personal Computer Workstations Ratio*	BNWS	Information Systems	Workstn Svcs Enterprise	ENTWKSWKS	S06	-	0.37	0.59	-	0.96	3.55	1.16	100.00
			PRWS	Information Systems	Workstn Svcs Enterprise PE	PREWKSWKS	P06	-	-	-	-	-	-	1.39	100.00
			DWSE	Information Systems	Workstn Svcs Enterprise DUK	DENTWKSWKS	D06	3.92	0.19	0.30	-	4.41	1.80	1.24	100.00
			PUWS	Information Systems	Workstn Svcs Utility PE	PRUWKSWKS	P12	-	-	-	-	-	-	1.39	100.00
	Development and support of distributed computer software applications (e.g., servers).	*Number of Info Systems Servers Ratio*	BNSS	Information Systems	Server Svcs Enterprise	ENTSYSSVR	S07	-	1.60	6.18	-	7.78	0.95	1.83	100.00
			PRSS	Information Systems	Server Svcs Enterprise PE	PRESYSSVR	P07	-	-	-	-	-	-	1.67	100.00
			DESS	Information Systems	Server Svcs Enterprise DUK	DENTSYSSVR	D07	9.76	0.85	3.26	-	13.87	0.50	1.58	100.00
			UTSS	Information Systems	Server Svcs Utility	UTISYSSVR	S13	9.86	0.85	3.30	-	14.01	-	0.97	100.00
			PUSS	Information Systems	Server Svcs Utility PE	PRUSYSSVR	P13	-	-	-	-	-	-	1.67	100.00
	Installation and operation of communications systems.	*Number of Employees Ratio*	BNTS	Information Systems	Telecom Svcs Enterprise	ENTEMPTEL	S33	-	0.70	0.89	-	1.59	3.62	1.27	100.00
			PRTS	Information Systems	Telecom Svcs Enterprise PE	PREEMPTEL	P33	-	-	-	-	-	-	1.43	100.00
			DETS	Information Systems	Telecom Svcs Enterprise DUK	DENTEMPTEL	D33	7.93	0.35	0.44	-	8.72	1.80	1.23	100.00
			DUTS	Information Systems	Telecom Svcs Utility	DUTIEMPTEL	D34	8.06	0.36	0.45	-	8.87	-	1.26	100.00
			UTTS	Information Systems	Telecom Svcs Utility	UTIEMPTEL	S34	-	0.73	0.92	-	1.65	-	1.31	100.00
			PTSU	Information Systems	Telecom Svcs Utility PE	PRUEMPTEL	P34	-	-	-	-	-	-	1.43	100.00
			BNHD	Information Systems	Helpdesk Services	ENTEMPHLP	S33	-	0.70	0.89	-	1.59	3.62	1.27	100.00
			DEHD	Information Systems	Helpdesk Services DUK	DENTEMPHLP	D33	7.93	0.35	0.44	-	8.72	1.80	1.23	100.00
			PRHD	Information Systems	Helpdesk Services PE	PREEMPHLP	P33	-	-	-	-	-	-	1.43	100.00
	Information systems management and support services.	*No. of Personal Computer Workstations Ratio*	BNMA	Information Systems	ITS Mgt & Apps Svcs Ent	ENT3RFITM	S35	3.92	0.19	0.30	-	4.41	1.80	1.24	100.00
			DEMA	Information Systems	ITS Mgt & Apps Svcs Ent DE	DENT3RFITM	D35	3.92	0.19	0.30	-	4.41	1.80	1.24	100.00
			PRMA	Information Systems	ITS Mgt & Apps Svcs Ent PE	PRE3RFITM	P35	3.92	0.19	0.30	-	4.41	1.80	1.24	100.00
			UTMA	Information Systems	ITS Mgt & Apps Utility	UTI3RFITM	S36	-	0.39	0.61	-	1.00	-	1.20	100.00
			DELH	Information Systems	Duke Energy Lighthouse	DUWKSITM	D11	4.00	0.19	0.30	-	4.49	-	1.24	100.00
			DUMA	Information Systems	ITS Mgt & Apps Svcs Util DE	DUT3RFITM	D36	3.92	0.19	0.30	-	4.41	1.80	1.24	100.00

2020 SERVICE COMPANY COST ALLOCATION DETAILS
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Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Meters	Procures, tests and maintains meters.	*Number of Customers Ratio*	DEMS	Meters	Meter Svcs Utility DE	DUTICUSMTR	D14	11.59	1.08	4.68	-	17.35	-	-	100.00
			UMMS	Meters	Meter Svcs Util MWonly Elec/Gas	UTMCUSMTR	S60	-	4.48	19.49	-	23.97	-	-	100.00
			UEMS	Meters	Meter Svcs Util MW Elec	UTECUSMTR	S58	-	-	-	-	-	-	-	100.00
Transportation	Procures and maintains vehicles and equipment.	*Number of Employees Ratio*	DUVE	Transportation	Transp Vehicles Utility DE	DUTIEMPVEH	D10	8.07	0.15	0.81	-	9.03	-	-	100.00
			UMVE	Transportation	Transp Vehicles Util MW only	UTMEMPVEH	S65	-	1.44	7.86	-	9.30	-	-	100.00
	Procures and maintains aircraft and equipment.	*Three Factor Formula*	DGAV	Transportation	Transp Aviation Gvnce	DGOVBFRAVI	DGL	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
								-	-	-	-	-	-	-	-
			DEAV	Transportation	Transp Aviation Svcs Ent DE	DENTBFRAVI	D03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	UTTR	Electric System Maintenance	ESS Elec Tran Utility	UTTOMETR	S15	-	-	-	-	-	-	-	100.00
			UMTR	Electric System Maintenance	ESS Elec Tran Utility - MW	UTTOMEMW	S96	-	-	-	-	-	-	-	100.00
	Services related to distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	UTDI	Electric System Maintenance	ESS Elec Dist Utility	UTTOMEDT	S16	-	-	-	-	-	-	-	100.00
			UMDI	Electric System Maintenance	ESS Elec Dist Utility MW only	UTMOMEDT	S57	-	-	-	-	-	-	-	100.00
Marketing and Customer Relations Grid Solutions	Advises the Client Companies in relations with domestic utility customers. Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*						-	-	-	-	-	-	-	-
			PUSD	Marketing and Customer Relations	M&CR SALES& Demand Util PE	PRUTSALMCR	P17	-	-	-	-	-	-	-	100.00
			NET	Marketing and Customer Relations	Customer Strategy R&S	UTISALNET	S75	-	-	-	-	-	-	-	100.00
			STD	Marketing and Customer Relations	Standard Services	UTISALSTD	S17	-	2.05	8.92	-	10.97	-	-	100.00
			MST	Marketing and Customer Relations	Mkt Sol - Sr vCp Duke Standard	UTMSOLSTD	D98	-	-	-	-	-	-	-	100.00
			UMSD	Marketing and Customer Relations	M&CR Standard Prod Util MW only	UTMSALNET	S68	-	4.48	19.49	-	23.97	-	-	100.00
			UMNT	Marketing and Customer Relations	M&CR Net Product Util MW only	UTMSALSTD	S68	-	4.48	19.49	-	23.97	-	-	100.00
			UESD	Marketing and Customer Relations	M&CR Sls&Dmnd Util MWElec only	UTMSALMCR	S66	-	-	-	-	-	-	-	100.00
			UGSD	Marketing and Customer Relations	M&CRSale&Demand Util MW Gas only	UTGSALMCR	S67	-	18.70	81.30	-	100.00	-	-	100.00
			DTNT	Marketing and Customer Relations	M&CR Elec Only Util DE	DUTICUSMCR	D75	-	-	-	-	-	-	-	100.00
			UTNT	Marketing and Customer Relations	M&CRSale&Demand Util MW Gas only	UTISANET	S75	-	-	-	-	-	-	-	100.00
	Advises the Client Companies in relations with domestic utility customers. Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	UTMR	Marketing and Customer Relations	M&CR Mtr Rdg&Pmt Proc Util	UTICUSPMT	S37	-	2.05	8.92	-	10.97	-	-	100.00
			DUMR	Marketing and Customer Relations	M&CR Customers Util ND	DUTICUSPMT	D37	-	1.22	5.30	-	6.52	-	-	100.00
			DUMS	Marketing and Customer Relations	Mkt Sol Srvco Utilities Std	DUTICUSPAY	D95	-	-	-	-	-	-	-	100.00
			UMMR	Marketing and Customer Relations	M&CR Mtr Rdg&Pmt Prc Util MWonly	UTMCUSPMT	S60	-	4.48	19.49	-	23.97	-	-	100.00
			UOMR	Marketing and Customer Relations	M&CR Mtr Rdg Pmt Prc DEO DEK only	UTOCUSPMT	S59	-	7.16	31.15	-	38.31	-	-	100.00
			DCTH	Marketing and Customer Relations	M&CR Customers Util ND	DGOVCUSCTA	DG6	-	1.22	5.30	-	6.52	-	-	100.00

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Marketing and Customer Relations Grid Solutions	Advises the Client Companies in relations with domestic utility customers. Customer services including the operation of call center.	*Number of Customers Ratio*	UEMR	Marketing and Customer Relations	M&CR MerRdg&PmtPrc Util MW Elec	UTEDUSPMT	S58	-	-	-	-	-	-	-	100.00
			UMPD	Marketing and Customer Relations	M&CR Util MW PD	UTMOUSMPD	S69	-	4.48	19.49	-	23.97	-	-	100.00
			DCIS	Marketing and Customer Relations	M&CR Cust Info Sys_Util	DUTICUSSYS	T05	-	1.22	5.30	-	6.52	-	-	100.00
			UWPD	Marketing and Customer Relations	M&CR PD DEO/DEK E/G	UTMOUSWPD	S70	-	7.16	31.15	-	38.31	-	-	100.00
	Advises the Client Companies in relations with domestic utility customers. Costs associated with Smart Grid activities	*Number of Customers Ratio*	USGA	Marketing and Customer Relations	M&CR Smart Grid All E/G	UTICUSSG	S76	-	2.05	8.92	-	10.97	-	-	100.00
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only	UTECUSSG	S77	-	-	-	-	-	-	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G	DUTICUSSG	D89	-	1.22	5.30	-	6.52	-	-	100.00
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only	DUECUSSG	D93	-	-	-	-	-	-	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES O&M	UTICUSSES	S84	-	2.05	8.92	-	10.97	-	-	100.00
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC E/G	PUTICUSSG	P91	-	-	-	-	-	-	-	100.00
			USGA	Marketing and Customer Relations	M&CR Smart Grid Util Capital	UTICUSSG	S80	-	2.05	8.92	-	10.97	-	-	100.00
			USGE	Marketing and Customer Relations	M&CR Smart Grid Electric Only Capital	UTECUSSG	S81	-	-	-	-	-	-	-	100.00
			DSGA	Marketing and Customer Relations	M&CR Smart Grid DUKE E/G - Capital	DUTICUSSG	D90	-	1.22	5.30	-	6.52	-	-	100.00
			DSGE	Marketing and Customer Relations	M&CR Smart Grid DUKE Elec Only - Capital	DUECUSSG	D94	-	-	-	-	-	-	-	100.00
			UTSG	Marketing and Customer Relations	Non-Smart Grid SES Cap	UTICUSSES	S85	-	2.05	8.92	-	10.97	-	-	100.00
			PSGA	Marketing and Customer Relations	M&CR Smart Grid PEC E/G - Capital	PUTICUSSG	P92	-	-	-	-	-	-	-	100.00
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G	DUTICUSGS	T01	-	1.22	5.30	-	6.52	-	-	100.00
			GIPA	Marketing and Customer Relations	M&CR Grid Strat&Plan DUKE E/G - Capital	DUTICUSGS	T02	-	1.22	5.30	-	6.52	-	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric	DUTECUSGS	T03	-	-	-	-	-	-	-	100.00
			GIPE	Marketing and Customer Relations	M&CR Grid Strat&Plan-Electric - Capital	DUTECUSGS	T04	-	-	-	-	-	-	-	100.00
Electric Transmission & Distribution Engineering & Construction - Designs and monitors construction of electric transmission and distribution lines and substations. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.	Transmission engineering and construction:	*(Electric Transmission Plant's) Construction - Expenditures Ratio*	UTET	Electric Transmission & Distribution	Eng & Constr ET Utility	UTICONETR	S18	-	-	-	-	-	-	-	100.00
			UEET	Electric Transmission & Distribution	Eng & Constr ET Util MW only	UTMCONETR	S62	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Distribution engineering and construction:	*(Electric Distribution Plant's) Construction - Expenditures Ratio*	UTED	Electric Transmission & Distribution	Eng & Constr ED Utility	UTICONEDT	S30	-	-	-	-	-	-	-	100.00
			UEED	Electric Transmission & Distribution	Eng & Constr ED Util MW only	UTMCONEDT	S61	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-

2020 SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Power Engineering & Construction	Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	*(Electric Production Plants) Construction-Expenditures Ratio*	UTEC	Power Engineering & Construction	Eng & Constr Pwr Prod Util	UTICONPWR	S25	-	-	-	-	-	-	-	100.00
			UEEC	Power Engineering & Construction	Eng&Constr Pwr Prod Util MW only	UTMCONPWR	S63	-	-	-	-	-	-	-	100.00
			UGEG	Power Engineering & Construction	Eng & Constr Gas Util MW only	UTMCONGAS	S64	73.95	4.92	21.13	-	100.00	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Human Resources	Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments. Supervises contract negotiations and relations with labor unions.	*Number of Employees Ratio*	DGHR	Human Resources	HR Svcs Gvnce	DGOMBMPHRS	DG2	7.92	0.15	0.79	-	8.86	1.80	-	100.00
			DHRE	Human Resources	HR Services Enterprise DE	DENTBMPHRS	D04	7.92	0.15	0.79	-	8.86	1.80	-	100.00
			UTHR	Human Resources	HR Services Utility	UTIBMPHRS	S38	8.07	0.15	0.81	-	9.03	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
Supply Chain - Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.	Procurement of materials and contract services and vendor payment processing:	*Procurement Spending Ratio*						-	-	-	-	-	-	-	-
			DUSC	Materials Management	Matls Mgmt Sply Chn Util DE	DUTLPROSPC	D19	8.49	0.70	1.52	-	10.71	-	0.29	100.00
			DBSC	Materials Management	Matls Mgmt Sply Chain Ent DE	DENTPROSPC	D08	8.24	0.88	1.47	-	10.39	2.98	0.29	100.00
			UPPD	Materials Management	M&W ELEC/GAS DELIVRY STOREROOM	UTBPROSMM	S72	-	4.07	11.42	-	15.49	-	-	100.00
	Management of materials and supplies inventory:	*Inventory Ratio*	UTIN	Materials Management	Matls Mgmt Inventory Util	UTIINVSPC	S20	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Facilities	Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.	*Square Footage Ratio*	GORE	Facilities	RE Facility Svcs CLT GO	CLTSQFFAC	S27	0.12	-	-	-	0.12	-	-	100.00
			CNRE	Facilities	RE Fac Svcs - Cincinnati	CINSQFFAC	S50	15.99	-	4.34	-	20.33	22.89	-	100.00
			PLRE	Facilities	RE Fac Svcs - Plainfield	PLDSQFFAC	S51	-	-	-	-	-	2.33	-	100.00
			MWRE	Facilities	RE Facility Services MW Utility	UTMSQFFAC	S71	-	2.51	10.60	-	13.11	-	-	100.00
			DBRE	Facilities	RE Facility Services Ent DE	DENTBFFAC	D39	8.43	-	0.14	0.31	8.88	0.93	-	100.00
Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	*Three Factor Formula*	DGAC	Accounting	Accounting Gvnce	DGOVBFACT	DG1	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DGVP	Accounting	VSP - Governance DE	DGOVBFPVSP	D63	-	0.41	1.68	0.01	2.10	3.12	0.08	100.00
			PGVP	Accounting	VSP - Governance	PRGVBFPVSP	P03	-	-	-	-	-	-	-	100.00
			DEAC	Accounting	Accounting Svcs Ent DE	DENTBFFACT	D03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
			UTAC	Accounting	Acctg Svcs Utility	UTIBFFACT	S09	5.91	0.40	1.63	0.01	7.95	-	-	100.00
			UMAC	Accounting	Acctg Svcs Util MW FERC only	UTMBFFACT	S53	-	2.34	8.76	-	11.10	-	-	100.00
			DDEP	Accounting	DEBS Depreciation DE	DENTBFFDEP	D49	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
			PRDP	Accounting	SvcCo Depreciation PE	PREBFFDEPR	P49	-	-	-	-	-	-	-	100.00

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Accounting	Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.	*Three Factor Formula*	DGDC	Accounting	Governance CTA Depreciation DE	DGOV3RDEPP	DG4	-	0.41	1.68	0.01	2.10	3.12	0.08	100.00
			DCTG	Accounting	CT A Governance DE	DGOV3RFCT A	DG3	-	0.41	1.68	0.01	2.10	3.12	0.08	100.00
			PNYG	Accounting	Piedmont CTA Gov	GOV3RFCTAP	DG7	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			PNGG	Accounting	Piedmont CTA Gov - Gas Only	GOV3FCT APG	DG6	74.75	4.96	20.29	-	100.00	-	-	100.00
			PUDC	Accounting	Governance CTA Depreciation PE	PRV3RDEPP	PG4	-	-	-	-	-	-	-	100.00
			GSAC	Accounting	Accounting Gas Only	UTI3FRGACT	GD3	74.75	4.96	20.29	-	100.00	-	-	100.00
		Generating Unit MW Capability Ratio (MDC)	DPNL	Accounting	Duke Progress CT A Nuclear	DGOV3FRDPN	CG3	-	-	-	-	-	-	-	100.00
	Rate of Return - Allocates the Service Company's portion of the utilities chargeback for affiliate use of space.	*Three Factor Formula*	DURR	Facilities Rate of Return Allocation	Facilities ROR Gvmce DE	DGOVMIRROR	CG4	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
Power Planning and Operations - Coordinates the planning, management and operation of Duke Energy Corporation's electric power systems including additions and retirements to Duke Energy Corporation's electric generation, transmission and distribution systems.	Generation planning:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUGE	Power Planning and Ops	Pwr Plng&Ops Gen Plng Util ND	DUTIPKLGPL	D21	-	-	-	-	-	-	-	100.00
	Transmission planning:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DUTP	Power Planning and Ops	Pwr Plng&Ops Trans Plng Util ND	DUTIPKLETR	D32	-	-	-	-	-	-	-	100.00
	Distribution planning:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Elec Peak Load Ratio						-	-	-	-	-	-	-	-
			DUDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util ND	DUTIOMEDL	D41	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	*Sales Ratio*	UTGD	Power Planning and Ops	Pwr Plng&Ops Gen Dsptch Util	UTISALGDP	S42	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Transmission Operations:	Weighted Average of the Circ Miles of Elec Transm Lines Ratio and the Elec Peak Load Ratio	UTTO	Power Planning and Ops	Pwr Plng&Ops Trans Ops Util	UTIOMIOTR	S31	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-
	Distribution Operations:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Elec Peak Load Ratio	UTDO	Power Planning and Ops	Pwr Plng & Ops Dist Ops Util	UTIOMIODL	S22	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.	*Generating Unit MW Capability /MDC Ratio*						-	-	-	-	-	-	-	-
			REPO	Power Planning and Ops	Pwr Plng & Ops Pwr Ops Reg	REBSCAPPOP	S28	-	-	-	-	-	-	-	100.00
			RCLO	Power Planning and Ops	Reg Coal - All Juris (DEBS)	RCLCAPPOP	D99	-	-	-	-	-	-	-	100.00
			RCTO	Power Planning and Ops	Reg CT/CC - All Juris (DEBS)	RCTCAPPOP	S98	-	-	-	-	-	-	-	100.00
			RMWO	Power Planning and Ops	Reg Coal/CT - Midwest (DEBS)	REBMCAPOP	S99	-	-	-	-	-	-	-	100.00

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Public Affairs	Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction, lithography, photography and video services.	*Three Factor Formula*	DGPA	Public Affairs	Pub Affrs Gvrnce	DGOV3FRPAF	DGL	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DGPP	Public Affairs	Public Policy Gvrnce	DGOV3FRPPO	DGL	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DIPA	Public Affairs	Public Affairs Services Ent DE	DENT3FRPAF	DI03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
	Utility Specific Activities	Weighted Average of # of *Customers Ratio* and # of *Employees Ratio*	UTPA	Public Affairs	Public Affairs Services Utilit	UTILSPAF	S24	9.83	0.62	2.75	-	13.20	-	-	100.00
								-	-	-	-	-	-	-	-
Legal	Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.	*Three Factor Formula*	DLEE	Legal	Legal Governance	DGOV3FRLEG	CGL	-	0.71	2.88	0.03	3.62	5.32	0.14	100.00
			ENLE	Legal	Legal Governance	GOV3FRLEG	DGL	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			PGLG	Legal	Legal Governance PE	PRGV3FRLEG	PGL	-	-	-	-	-	-	-	100.00
			UTLE	Legal	Legal Services Utility	UTI3FRLEG	S09	5.91	0.40	1.63	0.01	7.95	-	-	100.00
Rates	Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers' usage.	*Sales Ratio*	UTRA	Rates	Rates Utility	UTIS4LRAT	S44	10.51	1.46	7.89	-	19.86	-	-	100.00
			UORA	Rates	Rates Svcs Util DEO DEK only	UTOS4LRAT	S55	-	6.63	31.64	-	38.27	-	-	100.00
			UMRA	Rates	Rates DEO & DEK Reg	UTMS4LRAT	S86	-	8.45	45.74	-	54.19	-	-	100.00
Finance	Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.	*Three Factor Formula*	DGFI	Finance	Financial Svcs Gvrnce	DGOV3FRFIN	DG1	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DEFI	Finance	Financial Svcs DE	DENF3FRFIN	DI03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
			UTFI	Finance	Financial Services Utility	UTI3FRFIN	S09	5.91	0.40	1.63	0.01	7.95	-	-	100.00
			UMFI	Finance	Financial Svc Util MW REGonly	UTM3FRFIN	S53	-	2.34	8.76	-	11.10	-	-	100.00
Rights of Way - Purchases, surveys, records, and sells real estate interests for Client Companies.	Services related to electric distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*						-	-	-	-	-	-	-	-
			DURD	Rights of Way	Right of Way ED Sys Util ND	DUTIOMROWD	D87	-	-	-	-	-	-	-	100.00
	Services related to electric generation system:	*Elec Peak Load Ratio*						-	-	-	-	-	-	-	-
			DURG	Rights of Way	Right of Way Gen Sys Util ND	DUTIPKLRWG	D88	-	-	-	-	-	-	-	100.00
	Services related to electric transmission system:	*Circuit Miles of Electric Transm Lines Ratio*						-	-	-	-	-	-	-	-
			DURW	Rights of Way	Right of Way ET Sys Util ND	DUTIOMROW	D45	-	-	-	-	-	-	-	100.00
Internal Auditing	Reviews internal controls and procedures to ensure that assets are safeguarded & that transactions are properly authorized & recorded.	*Three Factor Formula*	DGIA	Internal Auditing	Internal Audit Gvrnce	DGOV3FRIAU	DG1	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DUIA	Internal Auditing	Intrnl Audit Svcs Utility DE	DUTI3FRIAU	DI09	5.91	0.40	1.63	0.01	7.95	-	-	100.00

2020 SERVICE COMPANY COST ALLOCATION DETAILS

COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total PNG	Total DEK-Gas	Total DEO-Gas	Total Comm Trans - Gas	Gas Utilities Total	Comm Pwr Total	Other Total	Total
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Three Factor Formula*	DGEA	Environmental, Health and Safety	Envir Affrs Gvmce	DGOV3FRENV	DGI	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
								-	-	-	-	-	-	-	-
			ENEA	Environmental, Health and Safety	Enviro Affairs Svcs Ent	ENT3FRENV	S46	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
	Utility Specific Activities	*Sales Ratio*	UTEA	Environmental, Health and Safety	Enviro Affairs Svcs Utility	UTISALENV	S47	10.51	1.46	7.89	-	19.86	-	-	100.00
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	UTFU	Fuels	Fuels Utility	UTISALFUE	S48	-	-	-	-	-	-	-	100.00
								-	-	-	-	-	-	-	-
Investor Relations	Provides communications to investors and the financial community, performs transfer agent and shareholder record keeping functions, administers stock plans and performs stock-related regulatory reporting.	*Three Factor Formula*	DGIR	Investor Relations	Investor Rel Gvmce	DGOV3FINV	DGI	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
								-	-	-	-	-	-	-	-
Planning	Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.	*Three Factor Formula*	DGPS	Planning	Planning Svcs Gvmce	DGOV3FRLN	DGI	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DGCD	Planning	Corp Dvlpmnt Gvmce	DGOV3FRDO	DGI	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			DBPS	Planning	Planning Svcs Enterprise DE	DENT3FRLN	D03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
			DUPS	Planning	Planning Svcs Utility DE	DUT3FRLN	D09	5.91	0.40	1.63	0.01	7.95	-	-	100.00
Executive	Provides general administrative and executive management services.	*Three Factor Formula*	DGEX	Executive	Exec Governance	DGOV3FREXC	DGI	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			ENEX	Executive	Exec Services Enterprise	ENT3FREXC	S03	5.73	0.38	1.58	0.01	7.70	2.92	0.06	100.00
			UTEX	Executive	Exec Services Utility	UTI3FREXC	S09	5.91	0.40	1.63	0.01	7.95	-	-	100.00
			UMEX	Executive	Executive Svc Util MW REG only	UTM3FREXC	S53	-	2.34	8.76	-	11.10	-	-	100.00
			UDEX	Executive	Exec Svcs Utility DEO DEK only	UTD8FREXC	S56	-	6.22	22.78	-	29.00	-	-	100.00
			DGSC	Executive	Stock Comp Legacy DE	GOV3FRSTK	C01	-	0.71	2.88	0.03	3.62	5.32	0.14	100.00
			DGEP	Executive	ESP Other Governance	DGOV3FRESP	DGF	5.73	0.38	1.58	0.01	7.70	2.92	0.07	100.00
			PSTK	Executive	Stock Comp Legacy PGN	PRGV3FRSTK	P01	-	-	-	-	-	-	-	100.00
Interest	Allocates Interest		DEAI	Interest	Acctg Interest Svc Enterprise DE	DENTINTACT	D52	5.76	0.47	2.11	0.13	8.47	1.25	-	100.00

I. GUIDELINES AND PROCEDURE FOR CHARGING AFFILIATES FOR COSTS ORIGINATING WITH DEC/DEP/PIEDMONT

On occasion, DEC/DEP/Piedmont's employees may be requested to provide support, subject to availability, to Affiliates and Nonpublic Utility Operations. DEC/DEP/Piedmont's management is responsible for ensuring that use of all company resources to support Affiliate work is properly charged to the Affiliate/Nonpublic Utility Operation. Rules regarding affiliate agreements between DEC/DEP/Piedmont and any Affiliate/Nonpublic Utility Operation are described in Section E. *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates* incorporated in this CAM. DEC/DEP/Piedmont will charge the Affiliate/Nonpublic Utility Operation the higher of fully distributed cost or market value. Charging the Affiliate/Nonpublic Utility Operation either market or fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. DEC/DEP/Piedmont's management is accountable for the review and approval of all charges from the utility in support of Affiliate/ Nonpublic Utility Operation work. An Affiliate Rules and Transactions CBT (emphasis on DEC/DEP/Piedmont) is available on the employee Portal.

Costs covered by the utility affiliate loader are handled by utility departmental allocations and a change to the Service Company allocation basis. These steps eliminate the need for a utility affiliate loader between DEC and DEP, because the costs of the utility affiliate loader are now addressed in a simplified fashion between the two Companies. The utility affiliate loader still applies for all labor charged outside of DEC and DEP to their affiliates.

The following procedure addresses employees' and management's responsibilities.

A. General Guidelines

1. Hours worked by DEC/DEP/Piedmont employees in direct support of an Affiliate/ Nonpublic Utility Operation are charged directly to the Affiliate.
2. First-line supervisors should review and approve, when appropriate, source

documentation resulting in a charge by DEC/DEP/Piedmont to an Affiliate/ Nonpublic Utility Operation (timesheets, employee expenses, etc.).

3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to an Affiliate/ Nonpublic Utility Operation.
4. Transactions originating with DEC/DEP/Piedmont and charged to an Affiliate typically require the completion and approval of a Service Request form. The process and eForm can be found on the Portal under Rates & Regulatory.

B. Time Reporting

When a DEC/DEP/Piedmont employee supports an Affiliate/Nonpublic Utility Operation:

1. Hours worked by DEC/DEP/Piedmont employees in direct support of an Affiliate/Nonpublic Utility Operation are charged directly to the Affiliate/Nonpublic Utility Operation.
2. Overtime hours worked by a non-exempt employee during a week should be applied first to the Affiliate/Nonpublic Utility Operation project, up to total hours worked on the project.
    a) If overtime pay is charged to the utility but not the Affiliate/Nonpublic Utility Operation in a time reporting period, the reason for the exception shall be fully documented and maintained by the supervisor for a minimum of two years.
    b) For example, a non-exempt employee works 50 hours for a given week, 10 of which must be paid as overtime. Twenty of the 50 hours were in support of an Affiliate project. That project should be charged 10 hours overtime and 10 hours straight-time.
3. When an exempt employee who is paid semi-monthly provides support to an Affiliate/ Nonpublic Utility Operation, and overtime is worked, the employee's regular semi-monthly pay is prorated to the utility and the Affiliate/Nonpublic Utility Operation based on the number of hours worked for each.
4. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for paid supplemental compensation.
5. The financial system will automatically load time reported to an Affiliate/Nonpublic

Utility Operation with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the business finance support group to appropriately adjust the costs to market. The overhead cost factor includes the following components: department administrative overheads, corporate governance, employee training, Service Company-related shared services, facilities, and supervisory costs.

C. Labor Allocations

DEC/DEP/Piedmont employees may provide services to their regulated Utility Affiliates at DEC's, DEP's, or Piedmont's fully distributed costs and DEC/DEP/Piedmont employees may provide services to Duke Energy Corporation, a Non-Utility Affiliate, a non-regulated Utility Affiliate or Nonpublic Utility Operation at the higher of fully distributed cost or market value, subject to certain exceptions. The mechanism for charging is generally a cost applied to labor charges and a market value journal entry if applicable. Allocation rates described in items 1 through 10 below are applied as a cost factor to direct labor charged to an Affiliate/Nonpublic Utility Operation.

Below are the various cost components of labor loads. The rates for Items 1-4 may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 are components of Duke Energy's Regulated Utilities Franchised Electric and Gas labor cost multiplier and are updated annually. Items 5-10 do not apply to transactions between DEC and DEP.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement, and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a

loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. **Incentive Allocation**

   Incentives are accrued via a loading factor applied to direct labor charges by the DEC/DEP/Piedmont employee performing work for an Affiliate/Nonpublic Utility Operation.

4. **Unproductive Cost Allocation**

   An unproductive cost allocation is applied on the basis of direct labor charges by the DEC/DEP/Piedmont employee performing work for an Affiliate/Nonpublic Utility Operation. DEC/DEP/Piedmont allocates unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Duke Energy intends to calculate Items 5-10 below on a total Regulated Utilities Franchised Electric and Gas ("FE&G") basis with the calculations to be performed annually. Annualized costs (either historic or projected) that best align with the current organization will be used in the calculations.

5. **Administrative Overheads**

   An Administrative Overhead Rate will be applied on the basis of direct labor charges. Administrative Overheads include: Departmental administrative functions (Business Support and General Office Executive Management), labor, and non-labor costs (e.g., training, employee expenses, Information Management costs for administrative functions by functional department).

6. **Corporate Governance**

   A corporate governance cost rate is applied on the basis of direct labor charges. The corporate governance rate is based on corporate governance costs allocated to FE&G.

7. Employee Training Costs

An employee training cost rate is applied on the basis of direct labor charges. The employee training-related costs factor will be developed by identifying the direct labor charges for those within Regulated Utilities that perform employee training-related tasks. Such training provides employees with the knowledge and skills necessary to perform their job duties, for professional development, and to maintain professional or technical licenses or for certifications required for business operations. The employee training cost rate is based on the total direct labor charges of the groups within Regulated Utilities that perform employee training-related tasks.

8. Service Company Costs

A service company cost rate is based on historical enterprise and governance overhead charged to Regulated Utilities in the following functions: Information Systems, Transportation, Human Resources, Materials Management, Accounting, Public Affairs, Legal, Finance, Facilities, Internal Auditing, Environmental, Health and Safety, Investor Relations, Planning, and Executive.

9. Facilities Cost

The facilities cost rate is applied on the basis of direct labor charges. The facility cost rate is based on the annual cost structure for corporate facilities, i.e., Charlotte, Raleigh, Cincinnati, St. Petersburg and Plainfield office buildings, and the number of employees occupying these facilities to arrive at an average facility cost.

10. Supervisory Costs

The supervisory cost rate is applied on the basis of direct labor charges. The supervisory cost rate represents the cost of supervision related to a Regulated Utilities employee performing work for an Affiliate Business unit. The basis for determining such costs is through the analysis of supervisory labor cost as a factor of Regulated Utilities employee labor cost.

D. Premium Services (Non-affiliate transactions)

Premium services are unregulated services provided by DEC, DEP or Piedmont to its respective utility customers. All costs related to premium services are either direct-charged or allocated to non-utility accounts. Costs identified in subsections C.1. through C.4. above are automatically allocated based on labor charges to premium services processes. An additional multiplier rate is also applied to labor charged to these premium services processes to cover costs such as facilities, administrative and corporate overheads, employee training and supervision, and shared services.

J. UTILITY TO UTILITY COST DISTRIBUTION DETAILS

The following are Utility allocations that run on Duke Energy Carolinas and Duke Energy Progress:

2020 Utility Level Allocations

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St.Cd	Total DEC	Total DEP	Total DEF	Total DEI	DBK Total	DEO Total	Electric Utilities Total	Gas Utilities Total	Total
Electric System Maintenance - Coordinates maintenance and support of electric transmission and distribution systems.	Services related to transmission system:	*Circuit Miles of Electric Transm Lines Ratio*	CTTR	Electric System	ESS Elec Tran Utility	CTTOMETR	C15	41.66	19.97	15.61	16.85	0.34	5.57	100.00	-	100.00
			PTTR	Electric System	ESS Elec Tran Utility	PCTTOMETR	C15	41.66	19.97	15.61	16.85	0.34	5.57	100.00	-	100.00
			CTDC	Electric System	ESS Elec Tran Utility	DODCMET	C98	67.61	32.39	-	-	-	-	100.00	-	100.00
			PTPC	Electric System	ESS Elec Tran Utility	PODCMET	C98	67.61	32.39	-	-	-	-	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
	Services related to distribution system:	*Circuit Miles of Electric Dist. Lines Ratio*	CTDI	Electric System	ESS Elec Dist Utility	CTDOMEDT	C16	39.77	25.92	15.39	11.48	1.11	6.33	100.00	-	100.00
			PTDI	Electric System	ESS Elec Dist Utility	PCTTOMEDT	C16	39.77	25.92	15.39	11.48	1.11	6.33	100.00	-	100.00
			CDDC	Electric System	ESS Elec Dist Utility	DCTCOMED	C93	60.54	39.46	-	-	-	-	100.00	-	100.00
			DPPC	Electric System	ESS Elec Dist Utility	PCTOMED	C93	60.54	39.46	-	-	-	-	100.00	-	100.00
Marketing and Customer Relations Grid Solutions - Advises the Client Companies in relations with domestic utility customers.	Design and administration of market solutions standard and/or operational programs.	*Number of Customers Ratio*	CTSD	M&CR	M&CR Sales & Demand Util	CUTTSALMCR	C17	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			PCSD	M&CR	M&CR Sales & Demand Util	PCUTTSALST	C82	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			MSPS	M&CR	Mkt Sol - DEP Leg Duk	DEPTSALSTD	U04	60.92	-	-	19.24	3.28	16.56	100.00	-	100.00
			CNET	M&CR	Customer Strategy P&S	CUTTSALNET	C75	60.92	-	-	19.24	3.28	16.56	100.00	-	100.00
			PCNT	M&CR	Customer Strategy P&S	PCUTTSALNE	C83	60.92	-	-	19.24	3.28	16.56	100.00	-	100.00
			CSTD	M&CR	Standard Services	CUTTSALSTD	C17	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			MSCS	M&CR	Mkt Sol - DEC Duke Std	DEOTSALSTD	U03	60.92	-	-	19.24	3.28	16.56	100.00	-	100.00
			CTNT	M&CR	M&CRSale&Demand Util	CUTCUSMCR	C74	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
			PCNA	M&CR	PEC Customer Bec Only	PCUSELEC	C78	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
			PFNA	M&CR	DEF Customer Bec Only	DECUSELEC	C79	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
	Customer meter reading, billing and payment processing. Market Solutions non P&L processes.	*Number of Customers Ratio*	CTMR	M&CR	M&CR Mtr Rdg&Pmt Proc Util	CUTCUSPMT	C37	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			PCDA	M&CR	M&CR Mtr Rdg&Pmt Proc Util	PCUTTCUSPM	C85	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			PFDA	M&CR	M&CR Mtr Rdg&Pmt Proc Util	FUTCUSPMT	C89	54.24	-	-	17.13	2.92	14.74	89.03	10.97	100.00
			CUMR	M&CR	M&CR Customers Util ND	CUTCUSPMT	C38	32.19	19.29	21.33	10.17	1.74	8.76	93.48	6.52	100.00
			CUMS	M&CR	Mkt Sol - DEC Utilities Std	CUTCUSPAY	C99	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
			PCMR	M&CR	M&CR Customers Util ND	PCUTCUSPM	C84	32.19	19.29	21.33	10.17	1.74	8.76	93.48	6.52	100.00
			PCMS	M&CR	Mkt Sol - DEP Util Std	PCUTCUSPAY	U02	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
			PFMR	M&CR	M&CR Customers Util ND	FUTCUSPMT	C88	32.19	19.29	21.33	10.17	1.74	8.76	93.48	6.52	100.00
			PFMS	M&CR	Mkt Sol - DEF Util Std	FUTCUSPAY	U01	34.43	20.64	22.82	10.88	1.86	9.37	100.00	-	100.00
			PFMW	M&CR	DEF M&CR MtrRdg&PmtPrc Util	FUTMCUSPMT	C60	-	-	-	37.42	6.39	32.22	76.03	23.97	100.00
			CMMR	M&CR	M&CR MtrRdg&PmtPrc Util MWonly	CUTMCUSPMT	C60	-	-	-	37.42	6.39	32.22	76.03	23.97	100.00
Electric Transmission & Distribution Engineering & Construction - Designs & monitors construction of electric transmission & distribution lines & substations. Prepares cost & schedule estimates, visits construction sites to ensure that construction activities coincide with plans, & administers construction contracts.	Transmission engineering and construction:	*(Electric Transmission Plants) Construction-Expenditures Ratio*	CTET	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ET Utility	CTCONETR	C18	22.62	15.41	38.32	12.45	2.11	9.09	100.00	-	100.00
			PTET		Eng & Constr ET Utility	PCTCONETR	C18	22.62	15.41	38.32	12.45	2.11	9.09	100.00	-	100.00
	Distribution engineering and construction:	*(Electric Distribution Plants) Construction-Expenditures Ratio*	CTED	Electric Transmission & Distribution Engineering & Construction	Eng & Constr ED Utility	CTCONEDT	C30	33.00	23.33	21.08	11.55	2.08	8.96	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
			PTED		Eng & Constr ED Utility	PCTCONEDT	C30	33.00	23.33	21.08	11.55	2.08	8.96	100.00	-	100.00
Power Engineering & Construction	Designs, monitors and supports the construction of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units or improvements to existing electric generating units. Prepares cost and schedule estimates and visits construction sites to ensure that construction activities coincide with plans.	*(Electric Production Plants) Construction-Expenditures Ratio*	CTCE	Power Engineering & Construction	Eng & Constr Pwr Prod Util	CTCONPWR	C25	41.35	20.09	15.94	20.11	2.51	-	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-

2020 Utility Level Allocations

Function	Function Description	Allocation Method	Operating Unit (OU)	Function	OU Description	Allocation Pool	St Cd	Total DEC	Total DEP	Total DEF	Total DEI	DEK Total	DEO Total	Electric Utilities Total	Gas Utilities Total	Total
Power Planning and Operations - Coordinates the planning, management & operation of Duke Energy Corporation's electric power systems. The activities of the Function include System Planning - planning of additions & retirements to Duke Energy Corporation's electric generation, transmission & distribution systems.	Generation planning:	*Elec Peak Load*	CTGE	Power Planning	Pwr Plng&Ops Gen Plng Util	CTIPKLGPL	C21	38.18	28.06	19.60	12.44	1.72	-	100.00	-	100.00
	Transmission planning:	*Elec Peak Load*	CTTP	Power Planning	Pwr Plng&Ops Trans Plng Util	CTIPKLETR	C32	37.85	22.67	19.10	12.12	1.32	6.94	100.00	-	100.00
	Transmission planning:	*Elec Peak Load*	PTTP	Power Planning	Pwr Plng&Ops Trans Plng Util	PCTIPKLETR	C32	37.85	22.67	19.10	12.12	1.32	6.94	100.00	-	100.00
	Distribution planning:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Elec	CTDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util	CTIDMIEDL	C41	38.81	24.29	17.25	11.80	1.21	6.64	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
	Distribution planning:	Weighted Avg of the Circ Miles of ED Lines Ratio and the Elec	PTDP	Power Planning and Ops	Pwr Plng&Ops Dist Plng Util	CTIDMIEDL	C41	38.81	24.29	17.25	11.80	1.21	6.64	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
Power Planning and Operations - System Operations - coordination of the energy dispatch and operation of Duke Energy Corporation's electric generating units and transmission and distribution systems.	Generation Dispatch:	*Sales Ratio*	CTGD	Power Planning	Pwr Plng&Ops Gen Disptch Util	CTISALGDP	C42	27.93	23.25	26.36	20.40	2.06	-	100.00	-	100.00
	Transmission Operations:	Weighted Average of the Circ Miles of Elec Transm Lines Ratio and the Elec Peak Load Ratio	CTTO	Power Planning and Ops	Pwr Plng&Ops Trans Ops Util	CTIDMIOTR	C31	39.78	21.31	17.35	14.48	0.83	6.25	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
	Distribution Operations:	Weighted Avg of the Circ Miles of ED Lines Ratio	CTDO	Power Planning and Ops	Pwr Plng & Ops Dist Ops Util	CTIDMIODL	C22	38.81	24.29	17.25	11.80	1.21	6.64	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
	Power Operations – provides management and support services for Duke Energy Corporation's electric generation system.	*Generating Unit MW Capability /MDC Ratio*	CEPO	Power Planning and Ops	Pwr Plng & Ops Pwr Ops Reg	CEGCAPPOP	C28	30.01	23.93	26.03	17.24	2.79	-	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
Environmental, Health and Safety	Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.	*Sales Ratio*	CTEA	Environmental, Health and Safety	Enviro Affairs Svcs Utility	CTISALENV	C47	28.68	20.29	13.19	10.09	1.31	6.58	80.14	19.86	100.00
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
Fuels	Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.	*Sales Ratio*	CTHS	Fuels	Fuels Utility	CUTSALHS	C48	27.93	23.25	26.36	20.40	2.06	-	100.00	-	100.00
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
								-	-	-	-	-	-	-	-	-
Nuclear	Provides general support services for the Nuclear fleet.	*Generating Unit MW Capability /MDC Ratio*	CNUE	Nuclear	DEC Nuclear Fixed Distribution	CUNUCENGI		66.70	33.30	-	-	-	-	100.00	-	100.00
			PNUC	Nuclear	PEC Nuclear Fixed Distribution	PUNUCLENGI		66.70	33.30	-	-	-	-	100.00	-	100.00
Fossil Hydro	Coal Combustion - provides centralized management, governance and support services for Duke Energy's Corporation's coal combustion residuals.	*MDC Ratio*	CCOM	Fossil	Coal Combustion Products O&M	DEC_CCOM		43.64	25.46	-	27.12	3.78	-	100.00	-	100.00

K. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH UTILITY AFFILIATES EXCLUDING THE SERVICE COMPANY

On occasion, Utility Affiliate (DEF, DEI, DEK, DEO-Transmission or DEO - Distribution) employees may be requested to provide support, subject to availability, to DEC/DEP/Piedmont. Affiliate management is responsible for ensuring that the use of all company resources to support DEC/DEP/Piedmont is properly charged to DEC/DEP/Piedmont. The Utility Affiliate will charge its fully distributed cost to DEC/DEP/Piedmont. Charging DEC/DEP/Piedmont fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. The Utility Affiliate management is accountable for the review and approval of all charges from the Utility Affiliate in support of DEC/DEP/Piedmont work. An Affiliate Rules and Transactions CBT (emphasis on DEC/DEP/Piedmont) is available in the Training Connection on the Portal.

Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, which addresses eliminating a utility affiliate loader between DEC and DEP. The following procedure addresses the responsibilities of employees and management.

A. General Guidelines

1. Hours worked by the Utility Affiliate employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. First-line supervisors should review and approve, when appropriate, source documentation resulting in a charge by Utility Operations to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors/managers are responsible for reviewing any reports that detail monthly charges to their responsibility center. These reports would include any charges incurred by the responsibility center to DEC/DEP/Piedmont.

4. Utility Affiliate to DEC/DEP/Piedmont transactions typically require the completion and approval of a Service Request form, unless DEC/DEP/Piedmont is requesting the service from the other. The process and eForm can be found on the Portal under Rates & Regulatory.

B. Time Reporting

When a Utility Affiliate employee supports DEC/DEP/Piedmont:

1. Hours worked by the Utility Affiliate employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for paid supplemental compensation.
3. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the Regulated Utility Financial Planning & Analysis group to appropriately adjust the costs to market. The overhead cost factor includes the following components: department administrative overheads, corporate governance, employee training, Service Company-related shared services, facilities, and supervisory costs.

C. Labor Allocations

Utility Affiliate employees provide services to DEC/DEP/Piedmont at fully distributed cost. The mechanism for charging DEC/DEP/Piedmont is generally a cost adder applied to labor charges and a market value journal entry if applicable. Allocation rates described in items 1 through 10 below are applied as a cost factor to direct labor charged to DEC/DEP/Piedmont. Below are the various cost components of labor loads. The rates for Items 1-4 may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 are components of Duke Energy's Regulated Utilities labor cost multiplier and are updated annually.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These

costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

2. **Payroll Tax Allocation**

   Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. **Incentive Allocation**

   Incentives are allocated via a loading factor applied to direct labor charges by each Utility Affiliate employee performing work for DEC/DEP/Piedmont.

4. **Unproductive Cost Allocation**

   An unproductive cost allocation is applied on the basis of direct labor charges by each Utility Affiliate employee performing work for DEC/DEP/Piedmont. Each Utility Affiliate allocates unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Duke Energy intends to calculate Items 5-10 below on a total Regulated Utilities basis with the calculations to be performed annually. Annualized costs (either historic or projected) that best align with the current organization will be used in the calculations. Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, details of Items 5-10. Items 5-10 do not apply to transactions between DEC and DEP.

5. **Administrative Overheads**
6. **Corporate Governance**
7. **Employee Training Costs**
8. **Service Company Costs**
9. **Facilities Cost**
10. **Supervisory Costs**

L. GUIDELINES AND PROCEDURE FOR CHARGING DEC/DEP/PIEDMONT FOR COSTS ORIGINATING WITH NON-REGULATED AFFILIATES

On occasion, employees of Non-Regulated Affiliates may be requested to provide support, subject to availability, to DEC/DEP/Piedmont. (Non-Regulated Affiliates' management is responsible for ensuring that use of all company resources to support DEC/DEP/Piedmont work is properly charged to DEC/DEP/Piedmont.) Rules regarding affiliate agreements between Non-Regulated Affiliates and DEC/DEP/Piedmont are described in Section E. *Guidelines for Transactions between DEC/DEP/Piedmont and Affiliates* incorporated in this CAM. Non-Regulated Affiliates will charge DEC/DEP/Piedmont the lower of fully distributed cost or market value as appropriate. Charging DEC/DEP/Piedmont either market or fully distributed cost is normally accomplished with the application of a percentage loaded on direct labor charges. Other charges may be made separately to account for vehicle charges, employee expenses, materials and supplies, contract services, etc. Non-Regulated management is accountable for the review and approval of all charges from Non-Regulated Affiliates in support of DEC/DEP/Piedmont's work.

The following procedure addresses employee's and manager's responsibilities.

A. General Guidelines

1. Hours worked by employees of Non-Regulated Affiliates in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. First-line supervisors should review and approve, when appropriate, any source documentation resulting in a charge by Non-Regulated Affiliates to DEC/DEP/Piedmont (timesheets, employee expenses, etc.).
3. First-line supervisors are responsible for reviewing reports that show monthly charges to their responsibility center. These reports would include charges incurred by the responsibility center to DEC/DEP/Piedmont.
4. Non-Regulated to DEC/DEP/Piedmont transactions typically require the completion and approval of a Service Request form. The process and eForm can be found on the Portal under Rates & Regulatory.

B. Time Reporting

When a Non-Regulated employee supports DEC/DEP/Piedmont:

1. Hours worked by Non-Regulated employees in direct support of DEC/DEP/Piedmont are charged directly to DEC/DEP/Piedmont.
2. Management approvals are required for non-exempt employee timesheets, as well as exempt employee timesheets for paid supplemental compensation.
3. The financial system will automatically load time reported to DEC/DEP/Piedmont with labor loads including fringe benefits, payroll taxes, incentive pay, and unproductive time, as applicable. If market value is to be charged, journal entries will be made by the Non-Regulated Affiliate's financial group to appropriately adjust the costs to market.

C. Labor Allocations

Non-Regulated employees provide services to DEC/DEP/Piedmont at the lower of fully distributed cost or market value. The mechanism for charging DEC/DEP/Piedmont is generally a cost adder applied to labor charges. When appropriate to charge market, a market value journal entry is made. Allocation rates described in items 1 through 10 may be applied as a cost factor to direct labor when charging DEC/DEP/Piedmont.

Below are the various cost components of labor loads which may be applied to labor when Non-Regulated Affiliates do work for and charge DEC/DEP/Piedmont. The rates for Items 1-4 (specific to Non-Regulated Affiliates) may be adjusted during the year to properly accrue the associated actual or anticipated cost. Items 5-10 may also be included as components of Non-Regulated Affiliates' labor cost multiplier.

1. Fringe Benefit Allocation

Fringe benefits are employee benefits such as retirement and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among business units.

2. Payroll Tax Allocation

Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among business units.

3. Incentive Allocation

Incentives are allocated via a loading factor applied to direct labor charges by the Non-Regulated employee performing work for DEC/DEP/Piedmont.

4. Unproductive Cost Allocation

An unproductive cost allocation is applied on the basis of direct labor charges by the Non-Regulated employee performing work for DEC/DEP/Piedmont. Non-Regulated Affiliates allocate unproductive costs pro rata to direct labor, either via a monthly ratio or standard rates.

Please reference Section I. *Guidelines and Procedure for Charging Affiliates for Costs Originating with DEC/DEP/Piedmont*, details of Items 5-10.

5. Administrative Overheads

6. Corporate Governance

7. Employee Training Costs

8. Service Company Costs

9. Facilities Cost

10. Supervisory Costs

M. TYPICAL TRANSACTIONS BETWEEN DEC/DEP/PIEDMONT AND AFFILIATES COVERED UNDER SEPARATE AGREEMENTS

The following are some of the typical transactions that DEC/DEP/Piedmont conduct with one another or their affiliates under separate agreements not otherwise discussed in this manual. The related agreements and others can be found on the State Regulatory Compliance Portal page, or are available upon request.

A. Bison Insurance

Duke Energy's Insurance program requires that costs be identified and allocated to the business units based upon their contributions to the risk of the entire company. The programs are designed to encourage risk control, early claims reporting, and efficient claims management and allow for cost-based pricing. This is accomplished by transferring the insurable losses across the company to the captive insurance companies, generally after a small business unit deductible is met. The captives also reinsure their risk in excess of its retention (and additional deductible) with unrelated third-party reinsurance companies. The captives charge premiums to business units that participate in the program to cover the aggregate cost of reinsurance and the estimated retained losses at the captives. This works essentially the same way commercial insurance works where the losses of a few are covered by the premiums of many.

The primary types of costs to be allocated are:

- retained losses and related loss adjustment expenses
- insurance premiums

Duke Energy has developed specific premium calculation methodologies for each line of coverage (i.e., general liability, property, workers' compensation and directors and officers), which is similar to how commercial insurance underwrites risk. Insurance premiums (costs) are generally allocated on a blended basis of exposure and historical loss experience (frequency and severity).

B. Intercompany Asset Transfer Agreement

An agreement among DEC, DEP, DEF, DEO, DEI, DEK, and Piedmont addresses the

transfer of assets, compensation, payment, warranties, and indemnification. The Commission approved a limited waiver of the cost-based pricing provisions of the Intercompany Asset Transfer Agreement for the transfer between DEC and DEP of rotable fleet spares, which are specific working parts of a generating unit that must be replaced several during the relatively long life of that unit. *Order Approving Request for Limited Waiver and Pre-Approval of Accounting Authority Pursuant to Rule R8-27*, Docket No. E-2, Sub 998A, E-7, Sub 986A (Sept. 3, 2014).

C. Tax Sharing Agreement

Duke Energy Corporation, as parent of a consolidated group of companies, files federal income taxes on behalf of its affiliates who are members of its consolidated group. Under Duke Energy Corporation's Tax Sharing Agreement, which is applicable to all members of Duke Energy's consolidated group, income taxes allocable to Duke Energy Corporation are accrued by it and consolidated group members on a stand-alone basis.

D. Utility Money Pool Agreement

Establishes a cash management program (the "Utility Money Pool") to coordinate and provide for certain short-term cash and working capital requirements.

E. Carolinas Operating Companies Commodity and Related Equipment and Services Transfer Agreement

Provides for the pre-approved transfer of fuel, reagents, coal combustion products, and related equipment and services (but does not provide for the disposal of coal combustion products). See *Order Accepting Affiliate Agreement and Allowing Payment Thereunder*, Docket Nos. E-2, Sub 998A and E-7, Sub 986A (Feb. 10, 2015).

F. Asset Management and Delivered Supply Agreement (AMA)

Provides for DEC to be the asset manager for all natural gas supply and capacity for both DEC and DEP. The AMA facilitates coordination and optimization of natural gas capacity and supply rights owned by DEC and DEP to reduce the cost of providing electric service to both DEC's and DEP's native load customers.

N. OTHER

Audit Principles & Guidelines

An audit trail shall exist with respect to transactions between DEC/DEP/Piedmont and its affiliates.

Corporate Audit Services will have complete access to affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with established policies and procedures and regulatory requirements. Auditors will have complete access to affiliate records to ensure availability of relevant information necessary to evaluate whether subsidization exists. The auditors, not the individual affiliates, will determine what is relevant for a particular audit objective. Limitation of access would compromise the audit process and impair audit independence.

Cost allocation documentation will be made available to Corporate Audit Services for periodic review of the allocation policies and procedures and to any jurisdictional regulatory authority when appropriate and upon request. Any entity required to provide access to its books and records can, and is encouraged to, make arrangements as necessary and appropriate to ensure that competitively sensitive information provided in the course of the audits be kept confidential by Corporate Audit Services and/or regulatory authorities.

Transactions between DEC/DEP/Piedmont and its Affiliates/Nonpublic Utility Operations will be reviewed at a minimum annually by Corporate Audit Services.

Piedmont Natural Gas Company Inc.
Docket 20-00086
CAD Data Request No. 1, Item 57

Indirect Overhead Pool

A. **Background and Purpose**

Certain work groups provide overall support to both O&M and Capital work, but which the direct charging of the work activities is impractical or impossible. In these cases, it is appropriate to charge the indirect overhead pool which systematically allocates defined costs. The indirect overhead allocations are designed to allocate the costs of management and supervision as well as support departments to operation & maintenance and capital accounts based on direct labor and contractor labor costs. Each business unit has its own set of allocations: Piedmont North Carolina, Piedmont South Carolina, Piedmont Tennessee, Piedmont 2 State, Piedmont 3 State, Duke Ohio, and Duke Kentucky.

B. Pool Design

The pool of dollars to be allocated is captured in specific operating units in Account 0186120 and is segregated between labor costs and non-labor costs. Charges into Gas Ops indirect overhead pools are made directly to the pools using the OUs and project ids shown in the table below.

O&M/Capital Split - Indirect Cost Pool			
Jurisdiction	**OU**	**Project**	**Activity**
North Carolina	PNFA	GASNCIND	X
South Carolina	PSFA	GASSCIND	X
Tennessee	PTFA	GASTNIND	X
2 State split NC/SC	PTSA	GAS2SIND	X
3 State split NC/SC/TN	PTHA	GAS3SIND	X
Ohio	GOF1	GASOHIND	X
Kentucky	GOF2	GASKYIND	X

C. Basis of allocation

The Gas Ops indirect overhead basis of allocation includes direct labor and contractor costs from Natural Gas Ops responsibility centers charged to O&M and Capital accounts. The allocation only charges the same jurisdiction as the pool (does not follow affiliate charges).

D. Finance Roles and Responsibilities

Gas Ops Finance monitors the charging into indirect overhead pool regularly and reviews with business partners and are corrected if necessary.

Capital only overheads

Piedmont Natural Gas Company Inc.
Docket 20-00086
CAD Data Request No. 1, Item 57

A. Background and Purpose

The Natural Gas Ops organization includes certain work groups, which provide, over-reaching overall support to capital direct work, but which the direct charging of the numerous individual direct work activities is impractical or impossible. In these cases, it is appropriate to charge the capital pool which systematically allocate defined costs over direct charged field labor to capital projects.

B. Pool Design

Charges into Gas Ops capital pools can be made directly to the pools using the OUs shown in the table below.

Jurisdiction	OU	Project	Activity
North Carolina	PNOA	107GASNC	I
South Carolina	PSOA	107GASSC	I
Tennessee	PTOA	107GASTN	I
2 State split NC/SC	PTSO	107GAS2S	I
3 State split NC/SC/TN	PTHO	107GAS3S	I

C. Basis of allocation

The Gas Ops capital pool basis of allocation includes direct labor and contractor costs from Natural Gas Ops responsibility centers charged to Piedmont capital projects. The allocation only follows Capital accounts and the business unit must be in the same jurisdiction as the pool (does not follow affiliate charges).

D. Capital Pool Groups within Gas Ops Organization

a. **Asset Management & Engineering –** Engineers are encouraged to direct charge when possible. Engineering performs the scoping and estimating for capital work which occurs on the front end of the project life cycle and are permitted to use the capital pool when detailed capital projects have not been set up yet or if an engineer works on a large volume of projects daily which would be impractical and inefficient to direct charge on an individual basis due to their short duration. Large program work that will span a longer duration should be charged directly to the specific project as soon as the detailed project has been created and identified. Engineers are asked to split their time between direct charge to individual projects, the capital pool for the related jurisdiction and O&M as appropriate.

b. **Regional Field & System Operations** –Management and supervision of the regional construction organizations are encouraged to direct charge when possible however due to the nature of overall management of all construction projects they are permitted to use the capital pool for their appropriate

jurisdictions. Managers and supervisors are asked to split their time between direct charge to individual projects, the capital pool for the related jurisdiction and O&M as appropriate.

E. Finance Roles and Responsibilities

Gas Ops Finance monitors the amount of time that Engineering, Regional Field and System Ops charge to the capital pool monthly and review with business partners. Charges into the capital pool from outside groups are reviewed quarterly and are corrected if necessary.

Fleet Allocation

A. Background and Purpose

The Piedmont Gas business units have costs related to their fleet of vehicles such as, maintenance, depreciation and fuel. These costs must be allocated to the correct Operations & Maintenance and Capital accounts depending on type of work the fleet vehicle is being used for. In order to do this, all fleet costs for Piedmont owned vehicles are charged to a cost pool account which then systematically spreads the costs over direct charged field labor.

B. Pool Design

Charges into fleet cost pool account 0803290 are made directly for each Piedmont business unit.

C. Basis of allocation

The fleet cost pool basis of allocation includes direct labor from the various Piedmont resource center operating units for each jurisdictional business unit.

D. Finance Roles and Responsibilities

Gas Ops Finance monitors the charging into fleet cost pool regularly and reviews with business partners and adjusts the allocation as necessary.

Stores Allocation – Supply Chain

A. Background and Purpose

The stores allocation process is designed to systematically distribute costs of supply chain personnel based on materials and supplies issuances.

B. Pool Design

Charges into stores cost pool account 0163110 are made directly for each Piedmont business unit.

C. Basis of allocation

The stores cost pool account 0163110 is credited each month for a fixed percentage of Direct Material Inventory (Resource Type 21000) and Direct Material Purchases (Resource Type 31000) charges to capital projects and O&M accounts for that month. The fixed percentage in 2018 was 9% and in 2019 it is 3%. The 2018 rate was initially chosen to be in line with the legacy Duke gas operations rates however was determined to be too high based on Piedmont activity. As an example, if a capital project had $10,000 in Direct Material Purchases charged to it in February 2019,the stores allocation for February 2019 is $300. The fixed percentage is determined based on an analysis of the inventory account balance and the balance in the 0163110 account. This rate is adjusted throughout the year to reach a stores balance of approximately 5% of the inventory balance by year end.

D. Finance Roles and Responsibilities

Gas Ops Finance monitors the charging into stores cost pool regularly and reviews with business partners and adjusts the allocation as necessary.

Working Stock/Depot – MRC monthly invoice

A. Background and Purpose

The working stock allocation process is designed to systematically distribute costs captured on the monthly invoice from MRC Global Inc. which details the use of small tools and equipment inventory at the operations centers.

B. Pool Design

Charges into working stock cost pool account 0154410 are made directly for each Piedmont business unit.

C. Basis of allocation

The working stock cost pool basis of allocation is regional operations and field customer service labor.

D. Finance Roles and Responsibilities

Gas Ops Finance monitors the charging into working stock cost pool regularly and reviews with business partners and adjusts the allocation as necessary.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-58. Page 9 of the Duke Energy 2019 10-K references the Innovation Center in Charlotte, which employs nearly 400 people dedicated to developing new products and services. With respect to this center respond to the following:

a. Are costs associated with this center assigned to Piedmonts' Tennessee operations? If so, respond to the following questions.

b. Identify the monthly costs incurred for the period January 2019 through June 2020 associated with the Center.

c. Provide a comprehensive explanation of how such costs are assigned to Piedmont Tennessee.

d. Provide a comprehensive listing of the new products and services developed that impact or are made available to Piedmont Tennessee customers.

RESPONSE:

a. Yes, there are costs associated with this center assigned to Piedmont's Tennessee operations through service company (DEBS) allocations. These DEBS charges to Piedmont are recorded on Piedmont's books to a 3-state business unit (BU). All charges recorded to Piedmont 3-state BUs are then allocated to TN, NC and SC for jurisdictional reporting purposes.

b. See Attachment 1 of 1.

c. The Innovation Center (Optimist Hall) is an office space and treated like other office space leased by the Company. Total lease and operating costs for the Innovation Center are paid by Duke Energy Business Services (DEBS) and allocated to the business units pursuant to the Cost Allocation Manual (CAM)

referenced in response to DR 1-57. A portion of the net amount charged to Piedmont is then allocated to Piedmont's TN operations for jurisdictional reporting purposes using the TN Composite Factor.

d. The following products were developed for use by the entire Natural Gas Business Unit and benefit Piedmont Tennessee customers by making operations more efficient and effective:

1) BEACON: This product is a mobile smart phone application which consolidates and prioritizes Atmospheric Corrosion Inspection (ACI). Atmospheric Corrosion Inspection consists of visually inspecting each customer's meter for corrosion (rust). It replaced outdated and out-of-support hardware which allowed for no functionality for using GPS location to efficiently complete these inspections with our team members who are already completing work in the same vicinity.

2) ACHIEVR: This product is a Virtual Reality Simulator for training our highest safety risk tasks (i.e. Pipe Purging) which cannot be simulated in a safe environment. The intent of this product is to develop muscle memory of the trainee with repetition so that when responding to an emergency or performing tasks on the pipeline the technician has an already established habit of the process or steps of the job to be performed. This is not intended to replace hands-on training but a supplement to refine the hands-on portion.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility and Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-59. Page 184 of the Duke 2019 10k indicates that the Piedmont business unit incurred $1 Million (rounded) of severance costs in 2019. To the extent any such costs are embedded within the expenses requested to be incorporated in Piedmont Tennessee rates within the pending case, respond to the following:

a. Identify the amount of costs i) allocated or ii) direct charged to Piedmont Tennessee operations in 2019.

b. Identify the title(s) of employees giving rise to the severance costs.

RESPONSE:

a. See CONFIDENTIAL attachment 1.

b. See CONFIDENTIAL attachment 1. See CONFIDENTIAL attachment 2 for Duke Energy's primary severance plan. See Eligibility Criteria for employee qualification. This plan covers most non-union employees, excluding executives.

Name and Title of Preparer: Patti Doster, Lead Accounting Analyst

Name and Title of Responsible Person: David Dye, Manager Accounting II

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-60. With respect to the employee(s) providing Governmental Relation services on behalf of Piedmont Tennessee provide the following information:

a. Copy of the job description of the employee(s).

b. Copy of the job description of the employee(s) to whom the employee providing Governmental Relation services reports.

c. Provide the 2019 labor, employee benefit costs and employee related taxes charged for the employee providing Government Relations services on behalf of Piedmont Tennessee by account charged. Within this response provide the portion of such costs by account related to incentive compensation.

d. Provide the 2019 labor, employee benefit costs and employee related taxes charged for the employee who supervises the employee providing Government Relations services on behalf of Piedmont Tennessee by account charged. Within this response provide the portion of such costs by account related to incentive compensation.

RESPONSE: Please see CONFIDENTIAL attachments.

Name and Title of Preparer: Jennifer Edwards, Lead HR Consultant

Name and Title of Responsible Person: Jake Stewart, Director – Compensation

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

State Government Affairs Dir | Job Code – 4358

JOB SUMMARY

Job Title
State Government Affairs Dir

Reports To (Job Title)
VP Rates and Natural Gas Supply

Job Type
N/A

Job Level
Expert

SUMMARY

This position has the responsibility for effectively managing and influencing the relationships with governmental officials and bodies to support the interests of Piedmont Natural Gas Company, Inc. in its Tennessee service territory. A key responsibility of the incumbent is developing and maintaining effective working relationships with Governor, executive branch staff, legislators and their staffs, counterparts within industries and organizations sharing similar interests, and those with significant expertise on issues of importance to the Company. The position manages state legislative strategy and relationships and coordinates with other companies, statewide businesses, industry organizations, coalitions, and special interest groups to foster and promote the interests of Piedmont. The position also supports and assists with the Company's economic development, community relations, sales & marketing, regulatory, business development, operations, and corporate communications initiatives within the region. This position maintains primary responsibility for making Company personnel throughout the organization aware of governmental and legislative issues.

RESPONSIBILITIES

Leads State Government Relations and Public Policy—80%

Represent the Company before governmental and legislative bodies and provides accurate, effective, appropriate and timely communication of the Company's position. Manage legislative issues by staying abreast of relevant information, consistently monitoring legislative, political, and regulatory activity, maintaining an active role in all relevant industry forums, utilizing available information technologies, consulting with other departments responsible for subject matter affected by proposed legislation, consulting with peer companies and taking necessary and timely action on issues of importance. Monitor and report on public policy issues/trends relevant to the industry. Maintain a familiarity and awareness of public policy trends nationally. Serve as a policy resource for the Gas Business unit leadership team.

Develop and execute legislative and agency regulatory actions to enable core business strategies. Additionally, this position develops and executes legislative strategies to defend and/or eliminate business risk in the form of legislative or regulatory actions which could have an adverse effect on Piedmont's business operations and/or its customers.

Develop and maintain effective working relationships with Governor, executive branch staff, legislators and their staffs, counterparts within industries and organizations sharing similar interests, and those with significant expertise on issues of importance to the Company.

Manage external lobbying contractors and resources. Negotiate contract terms, direct external lobbying duties, and evaluate performance of external lobbying team.

Establish relationships with state and local environmental and business regulatory agencies. Monitor proposed regulations for potential impact to PNG.

Support operational divisions with assistance in gaining permits, licenses, easements and any other permissions required from governmental entities for the purpose of doing business. Serve as liaison between operational divisions and elected officials to deliver information regarding planned and ongoing PNG projects. Work with Company's business development department to identify and explore potential business development opportunities within the public sector.

Serve as the PNG interface for State Chambers of Commerce, Tennessee Gas Association, and other statewide or regional groups of businesses engaged in advocacy or policymaking.

Recommend candidates for contributions from Piedmont Corporate Contributions; deliver contributions to candidates and attend political fundraising events to the extent permitted by state law.

Serve as the lead registered state lobbyist for the Company. Ensure compliance with applicable campaign finance and lobbying laws.

Regulatory — 10%

Support regulatory affairs group by serving as primary geographic liaison to regulatory agencies.

Provide support to regulatory affairs via strategy, relationships with regulators and regulatory staff, and participates in regulatory proceedings as requested by the regulatory affairs group.

Local Government Relations/Community/ Communications—10%

Monitor proposed city and county ordinances for purposes of determining potential effect on the Company; presents the Company's position to elected officials in the event of adverse impacts.

Manage municipal franchise agreement negotiations and renewals.

As a senior leader in the assigned state, develop and maintain relationships with key business and community leaders within the assigned state. Represent the Company in leadership roles within various civic, political, professional and membership organizations, provides presentations to groups as needed.

Initiate and maintain contact with state and, if applicable, with multi-county regional economic development organizations and provide general information requested by those organizations. Relay requests for information related to specific customers or prospects to the appropriate Sales or Major Accounts Services representatives.

Support Public Relations and other operational divisions by participating and offering input on topics of strategic importance, communications strategy, and crisis communications. Serve as a media spokesperson as needed.

ADDITIONAL DETAILS

- An extensive understanding of the state legislative process and the state political arena
- Ability to communicate effectively on complex policy issues and with executive management and with members of the state legislature and their staffs
- Ability to represent the company effectively in influential public forums
- Ability to build relationships people effectively
- Strong initiative
- Sound judgment to operate in fluid situations
- Experience as a registered lobbyist
- Experience working with business groups and grassroots initiatives
- A working knowledge of the electric, natural gas, or telecommunications industry, Utility franchise, and municipalization concepts and strategies
- Effective negotiation skills, Strategic planning development, implementation and tracking
- Strong written and verbal communications skills
- Highly effective interpersonal and influencing skills

SPECIFIC REQUIREMENTS

Eligible to register as a legislative lobbyist in the state

REQUIRED EDUCATION

Type of Degree	Field of Study
Bachelors	Political Science
Bachelors	Business Management
Bachelors	Business Administration
Bachelors	Communications

PREFERRED EDUCATION

Type of Degree	Field of Study
Masters	Business Administration
Doctorate	Law

REQUIRED WORK EXPERIENCE

7 years minimum required related experience

VP, Rates & NG Supply | Job Code – 800005

JOB SUMMARY

Job Title
VP, Rates & NG Supply

Reports To (Job Title)
SVP Natural Gas Business

Job Type
Supervisory/Management

Job Level
Vice President, Senior Vice President, President or Executive Vice President

SUMMARY

The Vice President, Rates & NG Supply has responsibility for developing, communicating, and executing the regulatory strategic plans for Piedmont Natural Gas as well as developing a comprehensive strategic planning and cost recovery planning framework, including coordination with the legal, legislative and accounting teams.

The Vice President, Rates & NG Supply acts as a principal advocate in all regulatory proceedings. The individual also develops and maintains constructive relationships with regulatory commissions (and their staffs), intervenors, and customer groups that are critical to the Company's financial success.

Position also ensures that the Company adequately plans and executes the acquisition of natural gas supply and capacity required to serve customers on the most critical day following its best cost policy in a safe and reliable manner and optimizes any available pipeline, storage and supply assets for the benefit of customers while maintaining compliance with all state and federal requirements. Further, leads the Company's initiatives to administer its natural gas transportation programs to serve customers and third-party marketers while providing accurate billing and management of imbalances, settlements and operational flow orders, ensuring compliance with Company tariffs and maintaining the integrity of the Company's pipeline system.

Additionally, this position oversees Piedmont's Community Relations. This group ensures that the Company adequately supports the communities it serves and responds to issues of concern to local citizens and leaders.

This role also supervises the State Governmental Affairs Director responsible for key external stakeholder relationships in Piedmont's Tennessee service territory.

RESPONSIBILITIES

50%: Direct and execute a comprehensive regulatory strategy for Piedmont Natural Gas. This includes planning, coordinating and preparing long-term regulatory strategies, in coordination with the financial planning group, for the utility to ensure that the Company's performance is maximizing shareholder value while maintaining competitive rates. The incumbent is charged with developing and maintaining relationships with the regulatory agencies to ensure that these plans are approved and implemented in a timely and efficient manner. Maintain expertise on relevant state laws and regulatory rules and policies. Direct the execution of utility rate cases, riders and trackers. Provide direction on interrogatory responses and testimony to support company positions.

30%: Lead Gas Supply Optimization and Pipeline Services function. Ensures that the Company adequately plans and executes the acquisition of natural gas supply and capacity. Optimizes available pipeline, storage and supply assets for the benefit of customers while maintaining compliance with all state and federal requirements. Further, lead the Company's initiatives to administer its natural gas transportation programs to serve customers and third-party marketers while providing accurate billing and management of imbalances, settlements and operational flow orders.

10%: Lead the Company's efforts to provide excellent service and support to the communities it serves.

5%: Lead the Company's efforts to effectively collaborate with key external stakeholders in the State of Tennessee.

5%: Develop organizational bench strength and improve each employee's skills through a combination of coaching, providing feedback, job rotation, cross training, and formal training. Provide one-on-one coaching, develop expectations and write performance appraisals. Ensure that all key work functions have an identified, capable and trained backup.

ADDITIONAL DETAILS

- Regulated experience;
- Strategic planning; collaborative skills, both internally and externally;
- Effective decision maker; strong leader with ability to see the big picture over the long term
- Experience in a regulated utility operating in Duke Energy's service territories.
- Public accounting, legal or other relevant experience outside of a regulated entity – a commercial perspective.
- Generation, Power Delivery or other operations and budgeting experience would be helpful but not required.

REQUIRED EDUCATION

Type of Degree	Field of Study
Bachelors	Accounting
Bachelors	Finance

PREFERRED EDUCATION

Type of Degree	Field of Study
Masters	Business Administration

REQUIRED WORK EXPERIENCE

10 years minimum required related experience

PROFESSIONAL CERTIFICATIONS OR LICENSES

Certified Public Accountant

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-61. With respect to home repair services provided by the partnership of Piedmont and HomeServe provide the following information:

a. Identify the monthly revenues and expenses by account associated with these services for the period January 2017 through the most recent information available.

b. Provide a comprehensive identification of Piedmont assets, including those of Duke Energy Business services which are used or accessed in the attempt to secure home maintenance related revenue.

c. For each asset, including tangible assets such as customer lists, indicate whether there is an assignment of these costs to the costs to provide this service line insurance function and how such costs are recorded on the books of Piedmont Tennessee.

d. Provide a comprehensive explanation of how the direct labor associated with the home maintenance function is determined and the account(s) to which it is charged on the books of Piedmont Tennessee.

e. Indicate the extent to which corporate cost allocations are assigned to the home maintenance activities. If such corporate cost allocations are not made, provide the justification for the lack of corporate cost assignment.

RESPONSE:

a See attachment.

b. No balance sheet exists for this non-utility activity. All marketing materials are processed by HomeServe, including development, postage and all other expenses.

Piedmont labor associated with HomeServe revenue is recorded under Home Warranty - Operating Expense

c. N/A

d. Labor and Overhead associated with the selling and administration of these activities is directly charged to Home Warranty - Operating Expenses - Salaries/OH

e. A portion of Corporate cost allocations are allocated for all of Duke non-regulated business to one Duke business unit rather than to each non-regulated business. Cost allocations are described in the Cost Allocation Manual, which was provided by the Company in its response to Request No. 57.

Name and Title of Preparer: Ellen V. Digh, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-62. Refer to Ms. Bowman's testimony. Provide the rationale supporting the use of a three-year amortization period to recover unamortized deferred pension costs contrasted with other possible amortization periods.

RESPONSE: Piedmont considers a three year period a reasonable time to recover the costs.

Name and Title of Preparer: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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Date Issued: August 17, 2020
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1-63. Identify any cost-reduction measures (expense) implemented since March 1, 2020 impacting a) PNG Tennessee direct operating expenses and b) expenses allocated to PNG-Tennessee. For purposes of this response identify only those measures with an estimated annualized impact of at least $100,000.

RESPONSE: Piedmont Natural Gas implemented 2 cost reduction mechanisms after March 1, 2020: 1) Travel & employee expense savings and 2) A limitation on new hires from outside the Company. Piedmont estimates these initiatives to contribute savings of $1.5M and $1.9M in O&M expenses respectively in 2020. Duke Energy Business Services (DEBS) also estimates $3.3M (Piedmont's portion) in expected savings from the same initiatives. Actual savings may vary from estimated amounts.

Name and Title of Preparer: Joel Rutledge, Director - Finance Gas Segment

Name and Title of Responsible Person: Joel Rutledge, Director - Finance Gas Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-65. Confidential: Regarding MFR 40, identify the Tennessee jurisdictional 2020 level of lease payments in any facility whose costs are allocated or direct charged to Piedmont-TN, attributed to the installation of Gas Systems as that terms is used within MFR 40.

RESPONSE: None of the Test Period lease expenses reflected in the Company's response to MFR item 40 were related to rental equipment or other property used directly for the installation of gas pipe.

Name and Title of Preparers: Kally Couzens, Manager - Rates & Regulatory Strategy; Paul Mosley, Rates & Regulatory Strategy Analyst; Bryan Manges, Director - Gas Util & Infrastructure

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-67. Regarding MFR 40 Attachment 1, specifically the DEBS Return on Assets, respond to the following:

a. Provide the monthly underlying gross plant and accumulated balances by asset on a total company basis which provide service to Piedmont-TN for the period April 2019 through March 2020.

b. Provide the monthly balance of Accumulated Deferred Income Taxes (ADIT) associated with assets identified in part a.

c. Provide the reconciliation of the December 2019 balance of Accumulated Deferred Income Taxes associated with assets identified in part a with the listing of all book/tax related timing differences.

d. Provide the underlying calculation for the DEBS Return on Assets for the months of December 2019 and March 2020, which tie to the amounts reflected for such items in MFR 40 Attachment 1, within the MFR 40 tab.

e. Provide a comprehensive explanation differentiating the return on DEBS assets Pension as contained in Column S, within the Confidential Vendor Details tab contrasted with the Pension and OPEB balances contained within the Working Capital Summary tab within the Revenue Requirement Summary.

RESPONSE: Please see the attachment.

Name and Title of Preparer: Jeff Masucci, Sr. Financial Analyst

Name and Title of Responsible Person: Jeff Setser, Director - Allocations and Reporting

PIEDMONT NATURAL GAS COMPANY, INC.
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1-68. Provide a copy of actuarial studies setting forth Piedmont Natural Gas Pension and OPEB expense for the years 2018 – 2020. If not readily identifiable within the report, identify the a) Minimum required funding level for each of the years and b) Minimum funding level required to avoid PBGC insurance.

RESPONSE: The minimum funding levels are identified in the attachment herein. Funding requirements are not included in the actuarial valuations.

Name and Title of Preparer: Jennifer Piasky, Senior Accounting Analyst

Name and Title of Responsible Person: David Dye, Accounting Manager II

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-69. Confirm that Piedmont employees participate within the Duke corporate pension plan. If so, provide a comprehensive explanation as well as actuarial studies addressing the impact on Piedmont-TN pension funding requirements and ongoing pension GAAP expense resulting from the merging of Piedmont pension obligations into the Duke pension plan.

RESPONSE: A subset of Piedmont employees participate in the Duke Energy Retirement Cash Balance Plan (RCBP). Piedmont employees hired or rehired after January 1, 2008 are not eligible for coverage under a pension plan. Piedmont employees hired before January 1, 2008, who previously participated in the Piedmont Pension Plan (Retirement Plan of Piedmont Natural Gas Company Inc.), had their pension benefit accrued as of December 31, 2017, frozen and merged into the Duke RCBP. There is no actuarial study addressing the impact of merging the plan with the Duke pension plan.

Effective January 1, 2018 these employees began accruing pension benefits under the cash balance formula, which is a monthly pay credit equal to 4 - 7% of eligible pay and annual interest credits of 4% of the account balance. At retirement, the vested pension benefit for legacy Piedmont employees will have at least two parts – a final average pay benefit and a cash balance benefit.

For the pension funding requirements on Piedmont Natural Gas, please refer to the Company's response to Request No. 68. Net periodic pension cost (income) for Piedmont Natural Gas for the years 2018 - 2020 is as follows:

2020 $(5,603,424)

2019 $(7,334,401)

2018 $(3,075,715)

2017 $9,839,388

Name and Title of Preparer: By David Dye, Manger Accounting II

Name and Title of Responsible Person: David Dye, Manger Accounting II

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-70. Provide schedules identical to those provided in MFR 14 for the period January 2020 through June 2020.

RESPONSE: See CONFIDENTIAL attachment.

Name and Title of Preparer: Paul Mosley, Rates and Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-71. Confidential – Please see the attached worksheet extracted from Confidential MFR-14, detailing selected items related to Account 923, Outside Services. With respect to the items listed provide the following:

a. A summary of the nature of the services provided by the vendor (if applicable)

b. A copy of the invoice supporting each charge

c. With respect to items that are unrelated to a specific vendor, describe the nature of the charge, any related accounting distribution associated with the charge and all supporting documentation for the entry made on the books of Piedmont.

RESPONSE: See CONFIDENTIAL attachment. A summary explanation for each item selected is shown in the attachment named "CAD 1-71 Attachment Confidential". See the remaining attachments for supporting documentation for each item.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-72. Regarding Other Benefits within the Summary tab of Schedule 5C, identify each employee benefit and its corresponding cost on a PNG-Tennessee basis and explain where such amounts may be traced to the Company's Trial Balance.

RESPONSE: Please see the file named "5F_OtherBen Adj" that was provided as part of the Company's response to MFR Item 12. The amount referenced in Schedule 5C can be found in Excel column P on the "5F_Other Ben Adj" file and each employee benefit is identified there in Column B. The general ledger details including account charged to support the test period per books amounts in Column D can be found on the tabs following the tab labelled Additional Support >>.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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Consumer Advocate's First Discovery Request
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1-73. Regarding the testimony of Brian Wesker, provide all material produced or obtained within Duke's due diligence review of Piedmont's records which documents the Maximum Allowable Operating Pressure (MAOP) of the Piedmont Transmission line prior to the 2016 acquisition.

RESPONSE: No Duke due diligence review materials regarding such MAOP was identified.

Name and Title of Preparers: Paul Mosley, Rates & Regulatory Strategy Analyst Doug Templeton, Rates & Regulatory Strategy Analyst; Kally Couzens, Manager - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Pia Powers, Managing Director - Gas Rates & Regulatory

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-74. Provide any information in the possession of Piedmont which demonstrates the cost of its OASIS system is comparable with the costs of similar systems of its peer natural gas utilities.

RESPONSE: Piedmont has no information responsive to this request.

Name and Title of Preparer: Jeremy Koster, General Manager - Gas Operations Support

Name and Title of Responsible Person: Jeremy Koster, General Manager - Gas Operations Support

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-75. Does the Company have the obligation to make any necessary repairs on service lines from the Main to the Meter, or is this the financial responsibility of the customer?

RESPONSE: Title to gas service lines, among other facilities, is vested in the Company. The Company would make any necessary repairs needed on service lines from the main to the meter. Repairs made to services through the Company's normal operations and maintenance activities would not be directly charged to the customer.

In accordance with Section 4 of Piedmont's Tennessee Service Regulations, and in accordance with the Underground Utility Damage Prevention Act, any repairs to service lines damaged by others shall be charged at the Company's actual repair costs. If the customer causes the damage, and was determined to be in violation of the Underground Utility Damage Prevention Act, the Company would make the repair to the damaged service line, and hold the customer financially responsible for the repair. The damage relief shall not come from the customer unless proven that the damage by the customer resulted from negligence on the customer's part.

Name and Title of Preparer: Scott Shepard, Manager - Field Customer Service

Name and Title of Responsible Person: Lori Benfield, VP - Gas Field Customer Service

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-76. Identify the number of Piedmont Tennessee service lines reflected within the property accounting records of the Company by customer class.

RESPONSE: Piedmont does not record the number of service lines by customer class in its asset accounting system. See the attachment which indicates the number of Tennessee service lines by Rate Schedule. The data in this attachment was extracted from Piedmont's Geographic Information System (GIS).

Name and Title of Preparer: Kally Couzens, Manager - Rates & Regulatory Strategy

Name and Title of Responsible Person: Monica Treverton, Director - Gas Asset Data Quality

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-77. Provide the target and actual results of all operating metrics relied upon by management to monitor the safety and quality of service for the calendar year 2019.

RESPONSE: Please see attached NGBU December 2019 Scorecard.

Name and Title of Preparer: Lauren Crowe, Director - Gas Business Transformation & Improvement

Name and Title of Responsible Person: Jeremy Koster, GM - Gas Operations Support

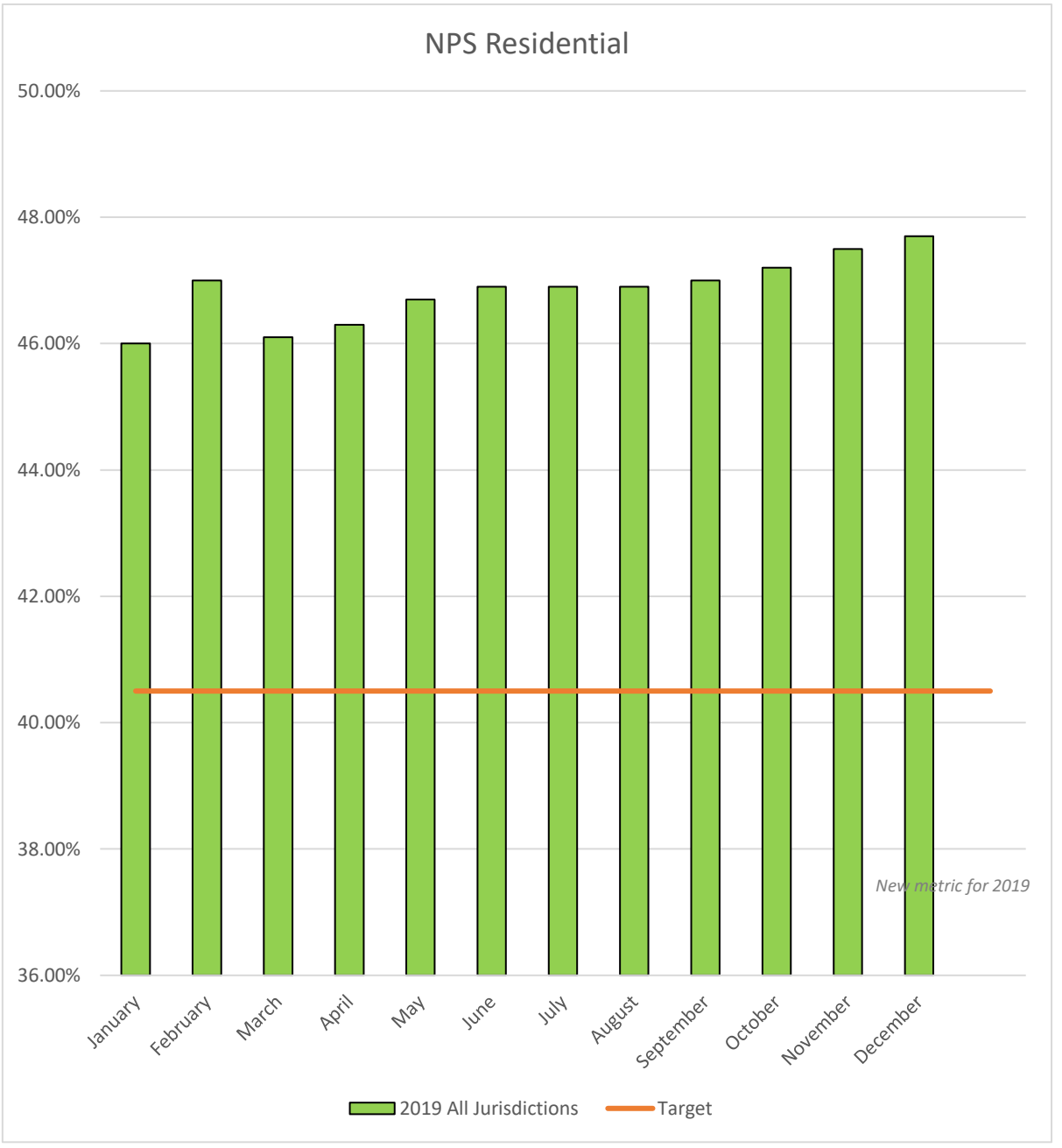
Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

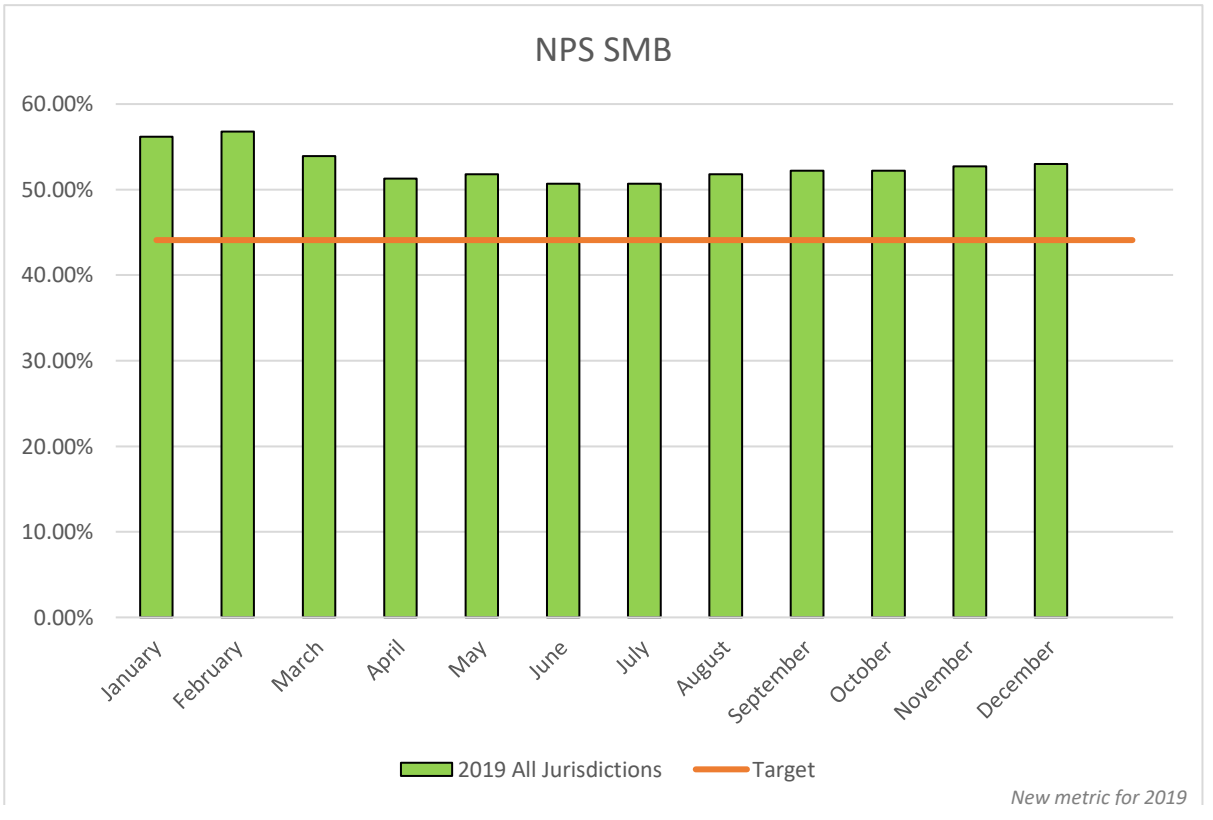
Gas Operations Performance Scorecard
Natural Gas Business Unit
December 2019

Metric Category	Performance Metric	2018 YTD Results by Gas Utility NC/SC/TN	2018 YTD Results by Gas Utility OH/KY	2019 MTD Results by Gas Utility NC/SC/TN	2019 MTD Results by Gas Utility OH/KY	2019 YTD Results by Gas Utility NC/SC/TN	2019 YTD Results by Gas Utility OH/KY	Notes
Customer	NPS - Residential	N/A	N/A	50.5% 40.5%		47.7% 40.5%		#N/A
	NPS - SMB	N/A	N/A	56.6% 44.1%		53.0% 44.1%		#N/A
	ECHO Customer Service	N/A	N/A	92.0% 92.75%		92.7% 92.75%		In the 4th quarter of 2019 , almost thirty percent of our workforce came to the floor from new hire training classes in preparation for light up. There were opportunities identified from our customer CSAT verbatims regarding our quality of service which were addressed through our Organizational Effectiveness Team. In addition, it was identified that a major source of customer dissatisfaction exists within our service order scheduling options as customers would like to have smaller appointment windows.
	Fastrack 2.0*	N/A	N/A	66.3%	63.2%	71.0%	61.8%	#N/A
Operational Excellence	Employee TICR	1.9		0 1.1		1.31 1.1		Continue Incident Review Calls for OSHA, PVAs, and Significant Near Misses; Continued Observation review (EFST- corporate and regional); Communicated the historical top 3 injuries incurred in the 1st quarter the last 5 years; NGBU OpEx is prepping for the NGBU Cultural Assessment – 2020; Continued field observations; Continued work on Risk Register and begin work on Safety Improvement Plan actions for 2020
	REEs	0		3 0		10 5		The driver for the "red" was a series of sediment releases from several large pipeline project ROWs. As a result of these sediment excursions outside of the LOD and the resulting impact on REE-2s, Amy and team have put together an improvement plan that includes a variety of short term and longer term actions to improve the design, implementation, and monitoring of BMPs (best mgmt. practices) to reduce these releases.
	Contractor Safety LAI	0		0 0		0 0		#N/A
	Preventable Vehicle Accidents	47		7 6		52 70		The NGBU had a December spike in PVAs that caused the measure to go "red". Actions we are taking in 2020 include raising the awareness on PVA metrics (dashboard) , adding in regular content to Tuesday safety calls for driving best practices, evaluating a safe driving recognition program, taking steps to increase the visibility of our fleet vehicles, and have added a member of the Fleet Services Team to our NGBU Event Free Steering team to help drive fleet improvements.
	Damages per Locate	1.82	3.07	2.42 3.26		2.45 2.25		Charlotte, Nashville, Kellogg and Anderson had the largest increase by Resource Centers. The breakdown of year end DPT for 2020 by state is: KY 2.34, NC 2.40, OH 3.01, SC 3.04 & TN 2.76. In NC, the breakdown of DPT's is by zones is Central 3.03, North 2.45, South 2.13, Southeast 1.58 and East 1.47. In 2020 we will be continuing the Watch & Protect and Untoneable remediation programs in OH and will be starting in KY, NC Central and North Zones due to the available deferral & rate case funding mechanisms in place in these states.
	Regulatory Findings	2		0 1		0 1		#N/A
	Cybersecurity Performance Index*	N/A		0		0		#N/A
	Natural Gas Outages / Reliability	3		0 0		1 2		#N/A
	Emergency Response Time (mins)	35	36	35 34	37 35	33.7 34	36.0 35	FCS OHKY experienced an increase in the create to dispatch and dispatch to acknowlege time segments of total emergency response. FCS is actively working with the DCC and Customer Facing Work Order Process Owner, Jonathan Cabeza to determine the root cause and corrective actions for this increase.
	Work Order Completion (days)	2.9	3.8	1.9 4	2.9 4	2.0 4	3.5 4	#N/A
	Leaks Detected	7.07	9.14	0.51 0.60	1.09 0.90	5.58 7.20	11.66 10.80	In December, leak survey concentrated on transmission mains and no leaks were found. There were a total of 147 distribution system leaks reported in December and 58 were reported over the main and 89 reported over services. The leading cause of leaks on services was corrosion and natural forces and the leading cause on mains was equipment. Work will continue in 2020 on service replacements in particular replacing existing copper services.
Growth	Total Customer Additions	19,456	4,424	1,862 1,928	405 386	21,202 20,304	4,729 4,050	Fewer home closings realized in December. Sales management is reviewing opportunity pipeline.
	Gas Segment Net Income Growth ($mil)	N/A	N/A	$76.0 $74.3		$451.2 $373.0		#N/A
	O&M Expenses ($mil)	N/A	N/A	$48.3 $36.0		$437.7 $406.0		
Employee	Diversity & Inclusion	N/A		TBD		TBD		#N/A
	Regrettable Attrition	N/A		TBD		TBD		#N/A
	Operational Excellence (NERC Issue)	N/A		TBD		TBD		#N/A
	Employee Engagement & Enablement	N/A		TBD		TBD		#N/A
Service Provider Metrics	SCADA Reliability	N/A		0 0		6(3640) 0		Outages in the month(s) of: Jan - 30 mins; May - 180 mins ; July - 360 mins; August - 180 mins; Sept - 2880 mins (*Huntersville LNG Plant; 48-hr network outage); Oct - 10 mins
	Call Center Outages	N/A		0 0		0 0		#N/A
	Significance Network Outages	N/A		0 0		0 0		#N/A

*Baseline year; no target tracked for 2019

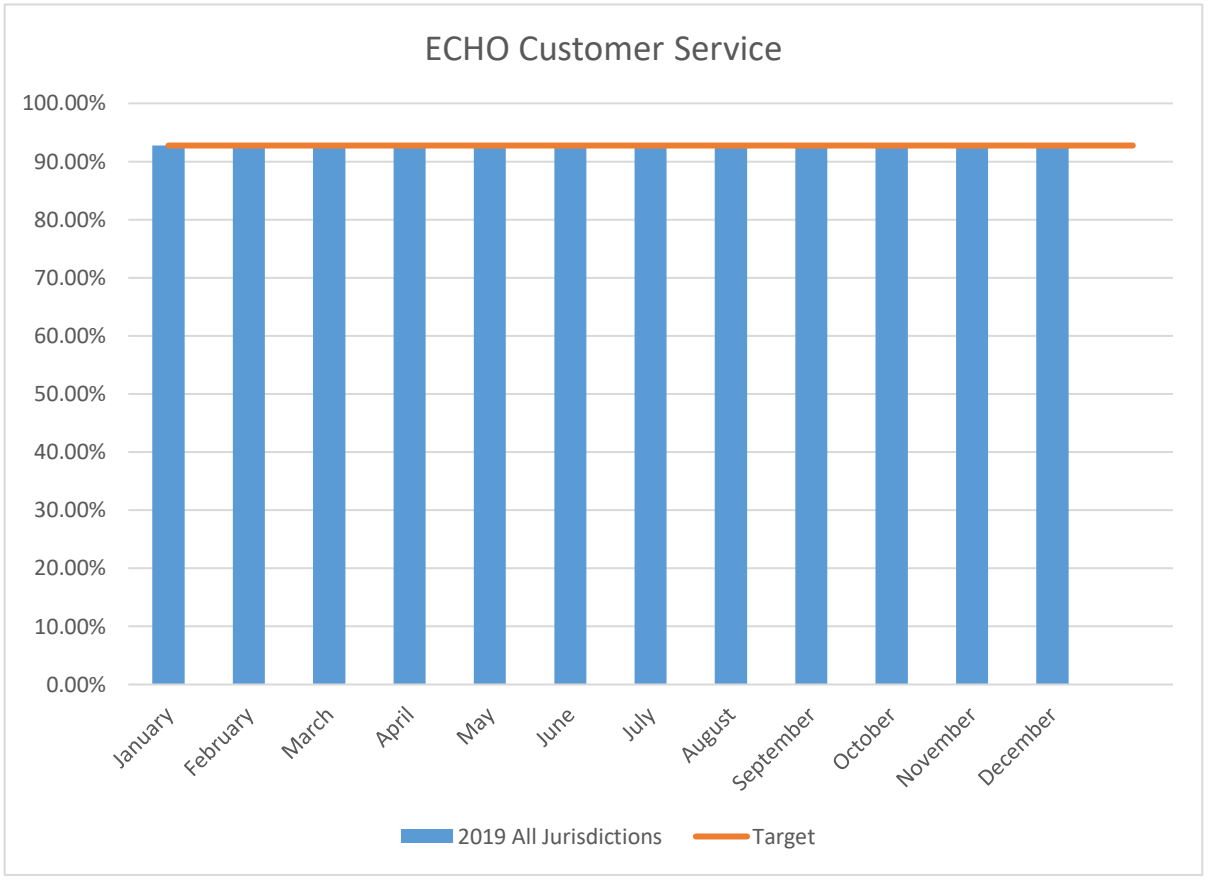
Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Customer

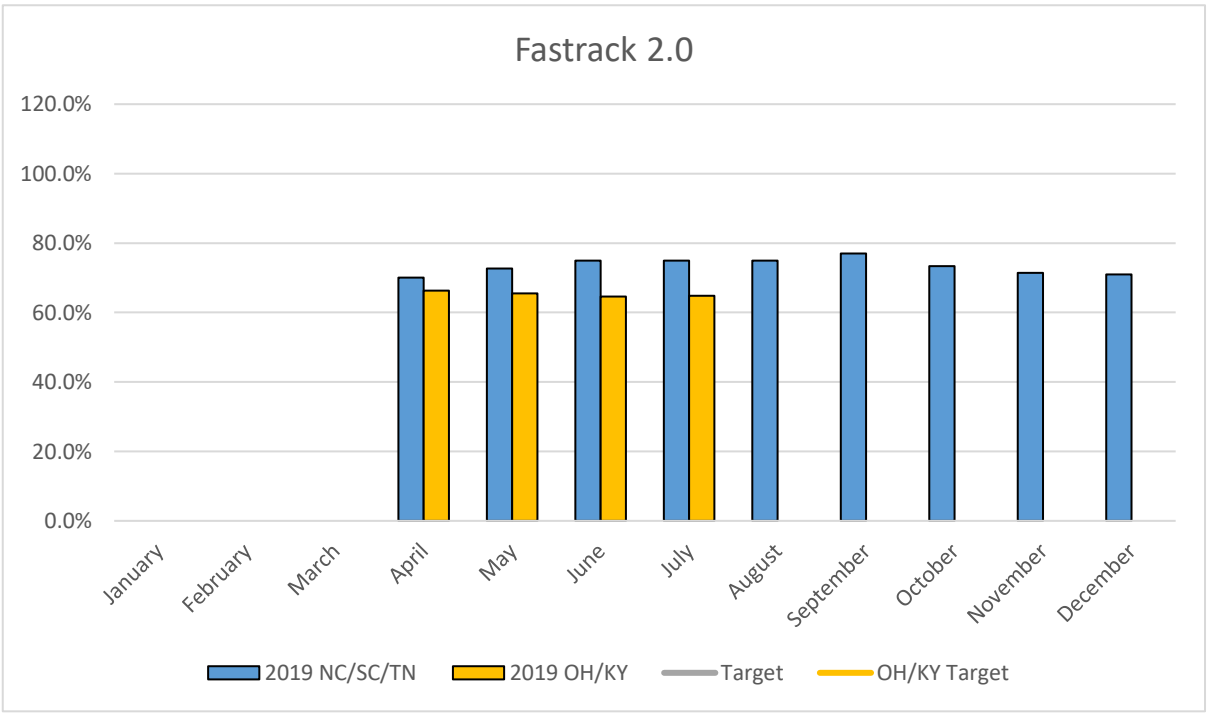




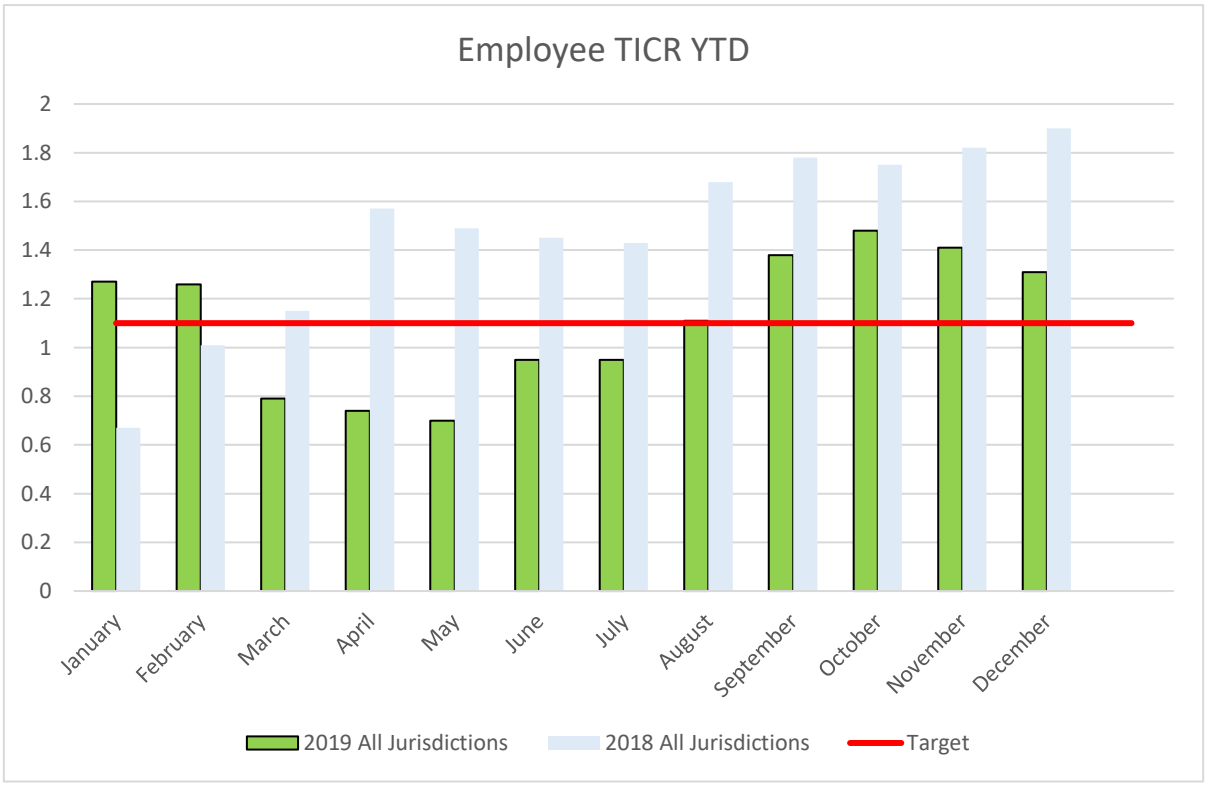
New meeting for 2023

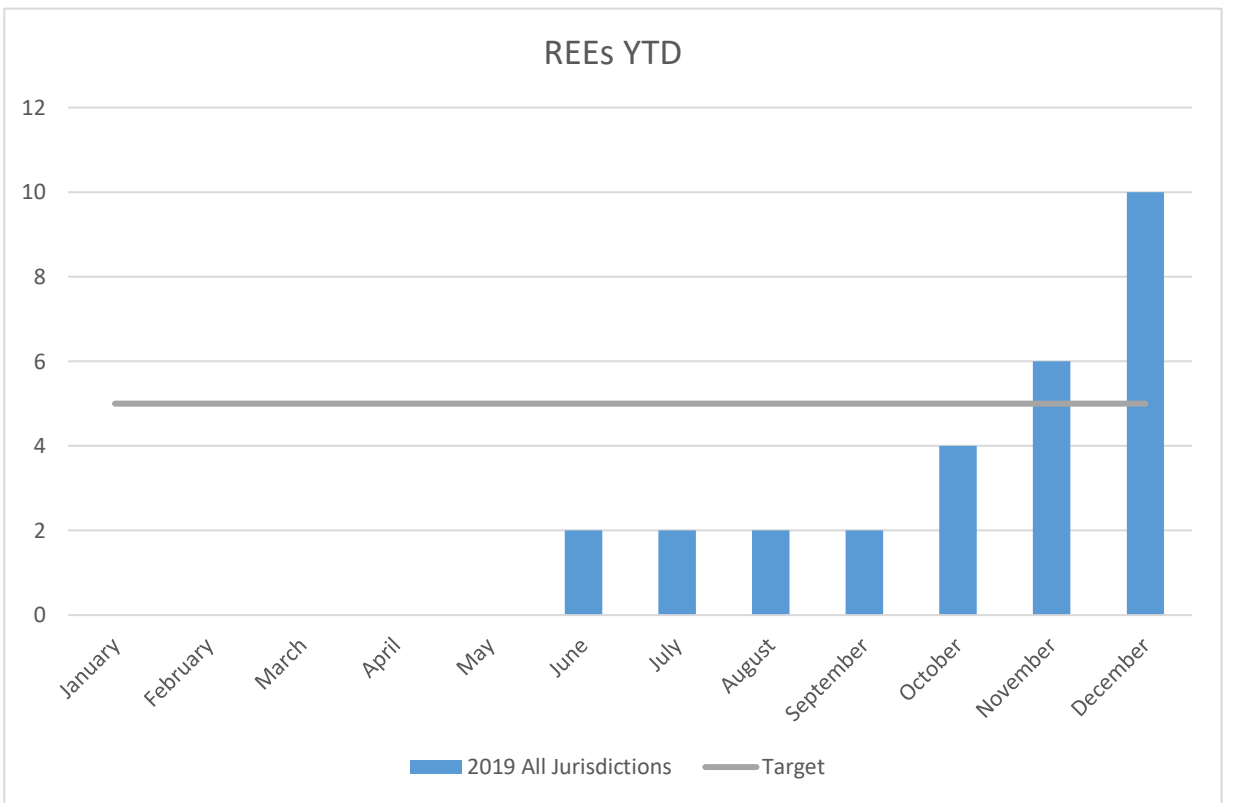
Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Customer



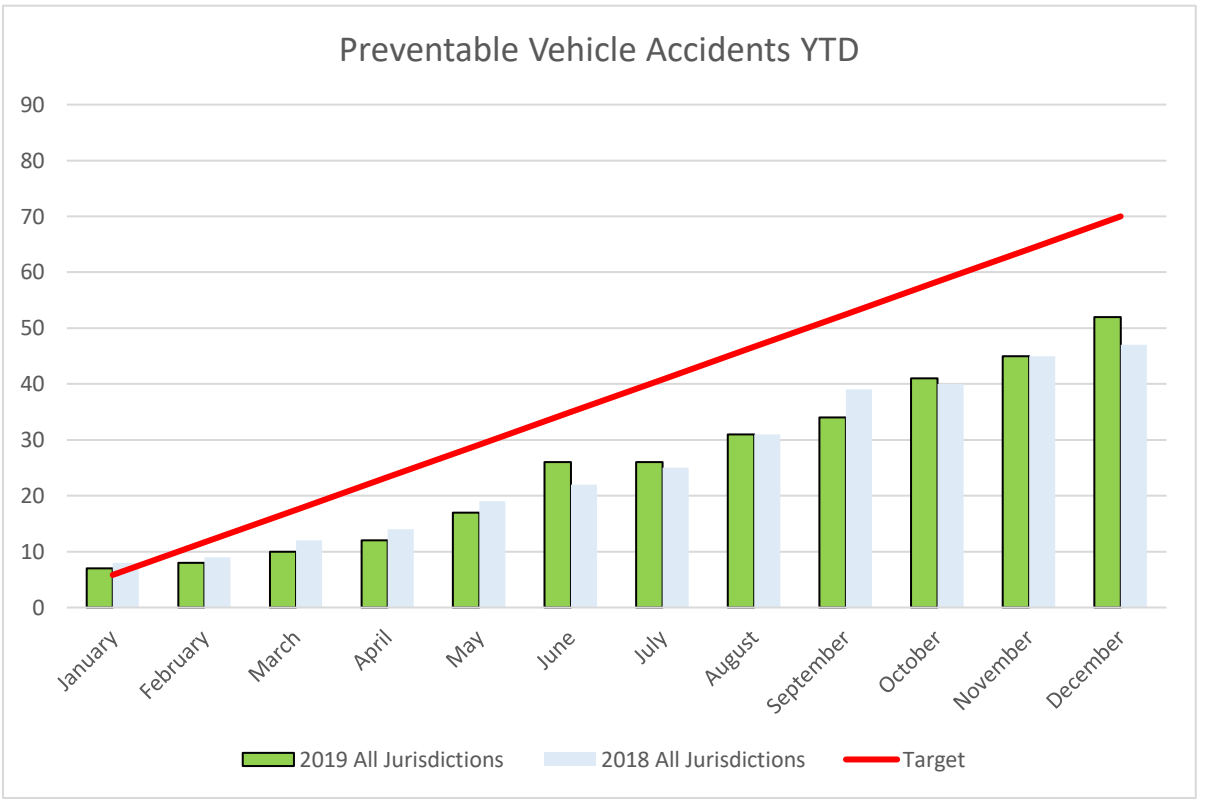


Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence

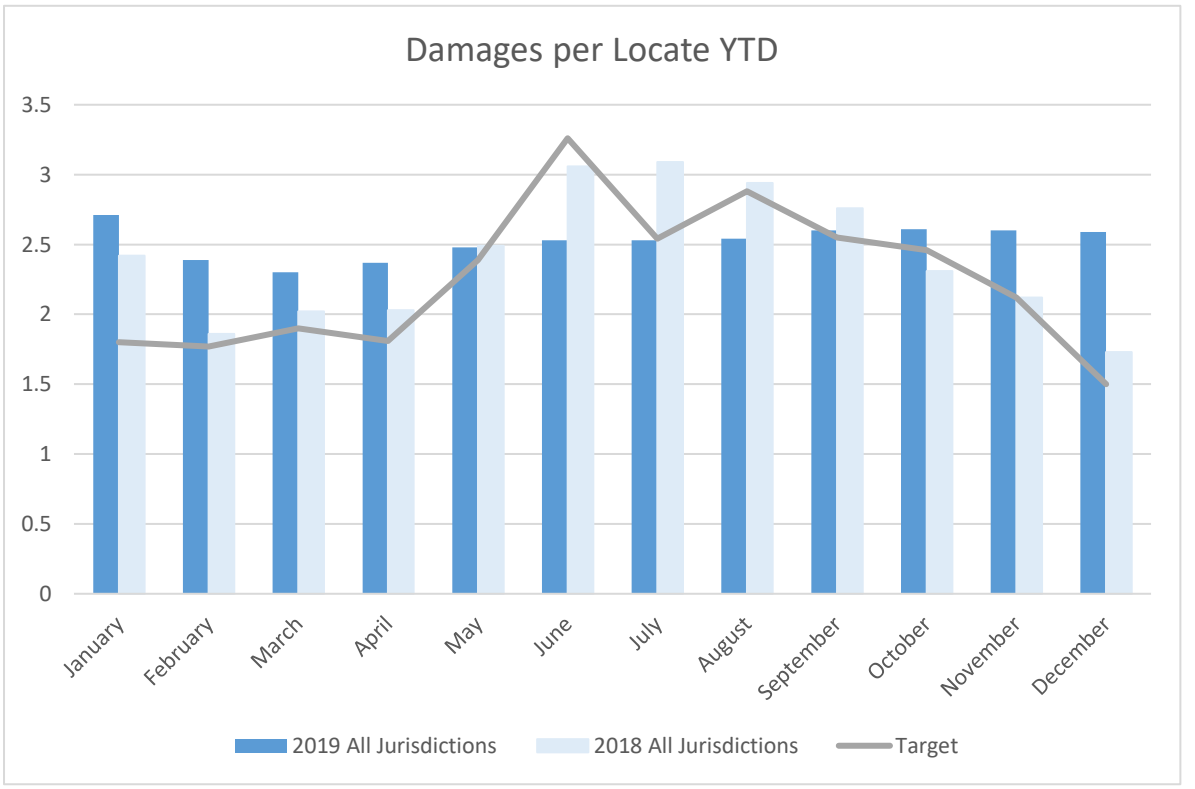


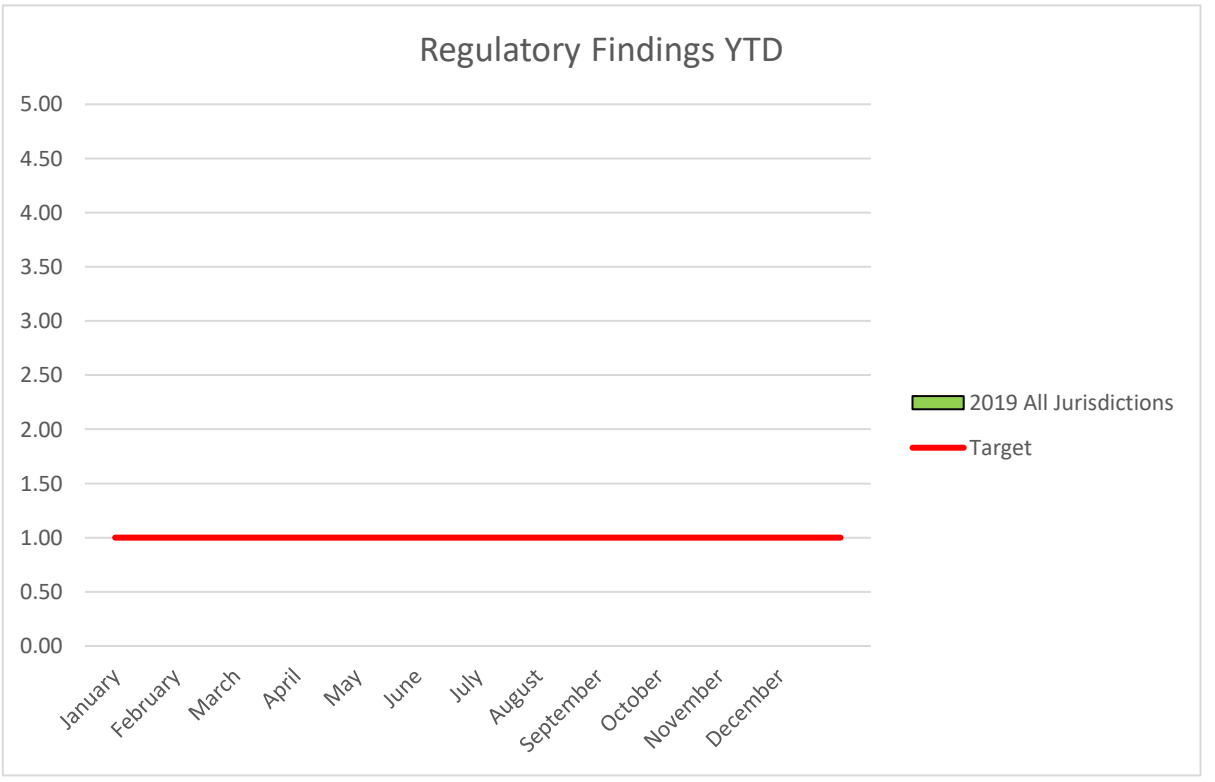


Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence

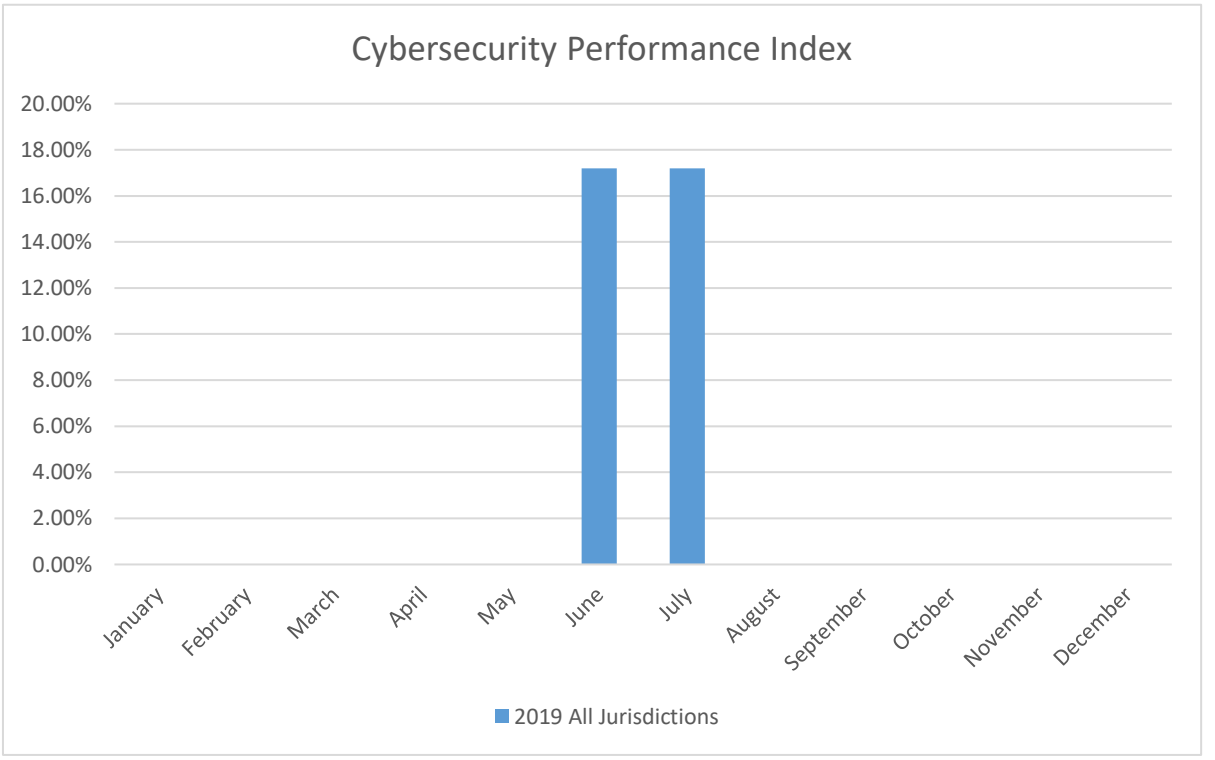


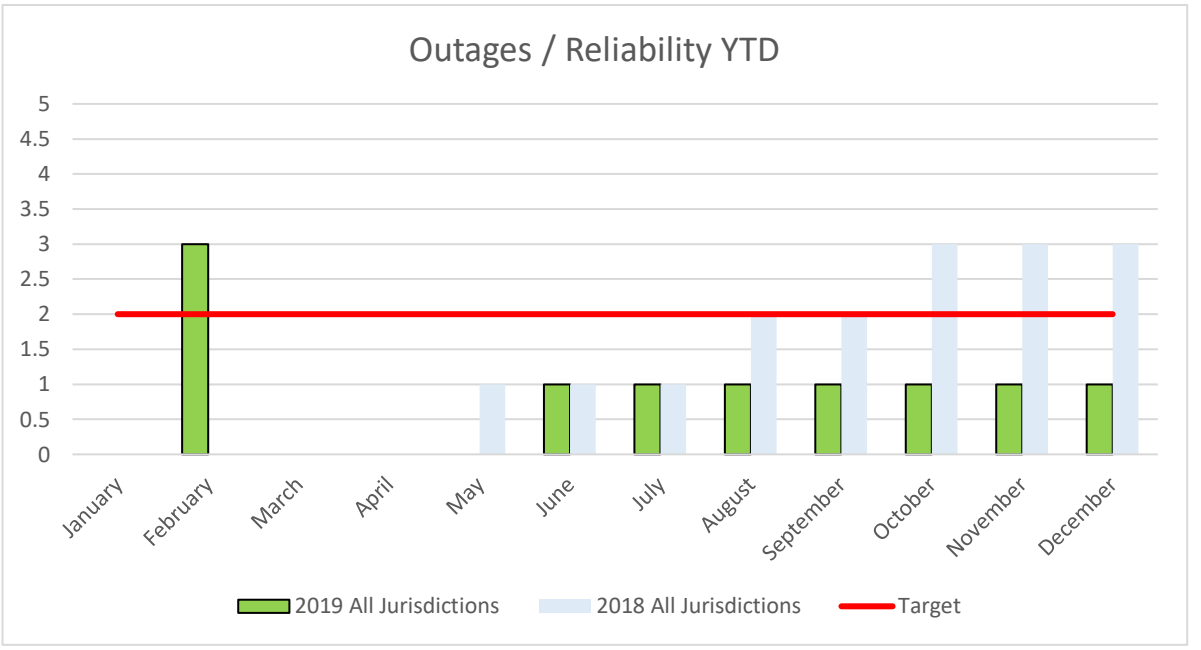
Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence



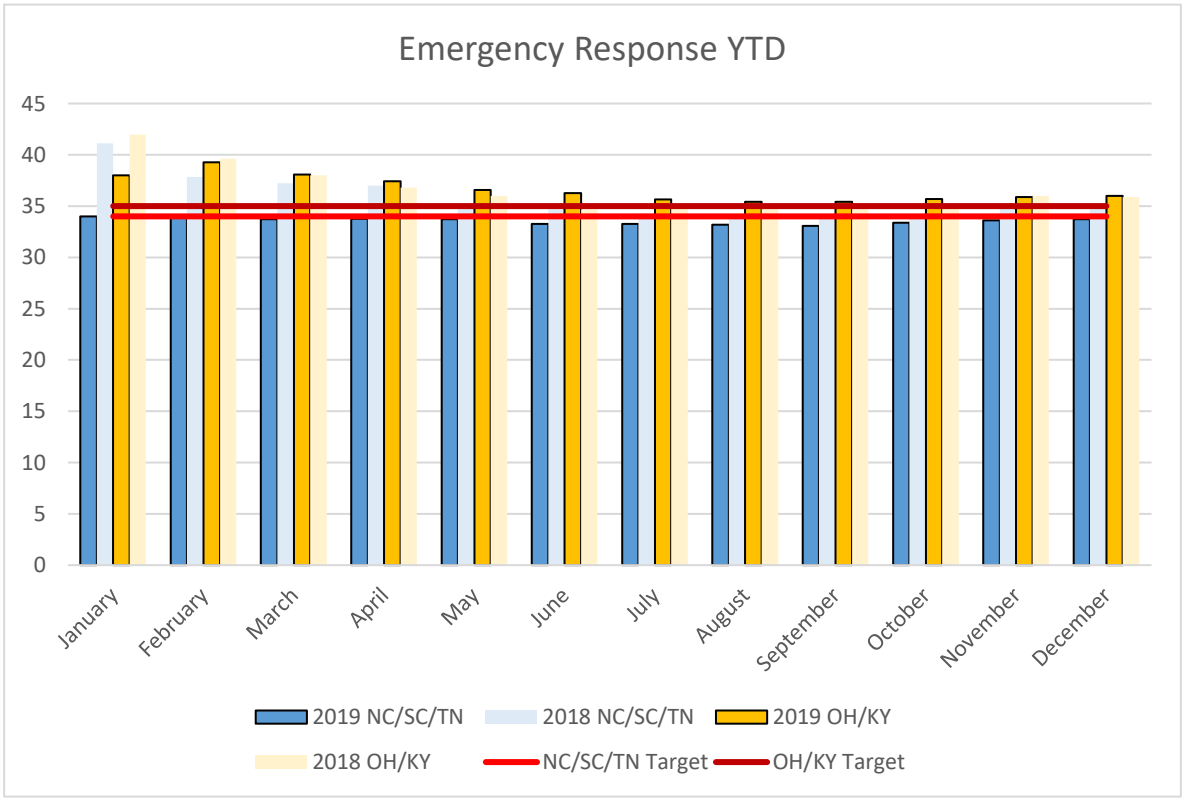


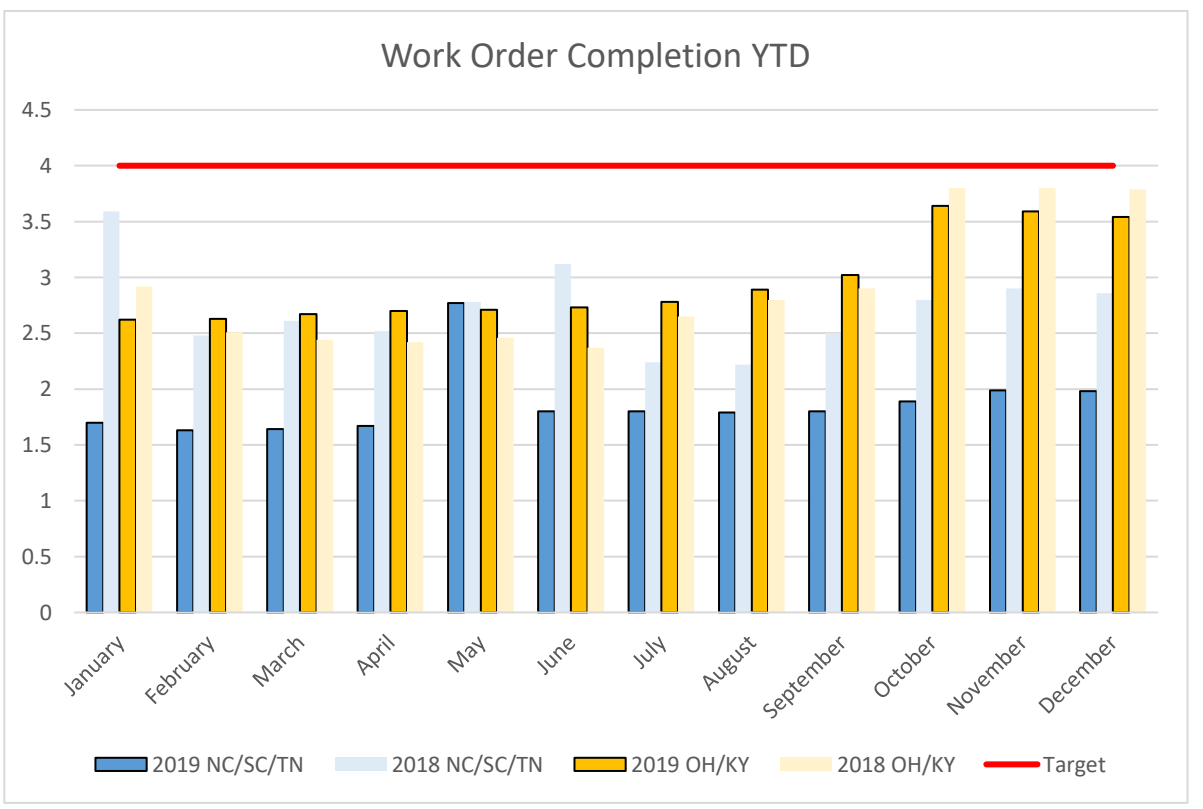
Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence



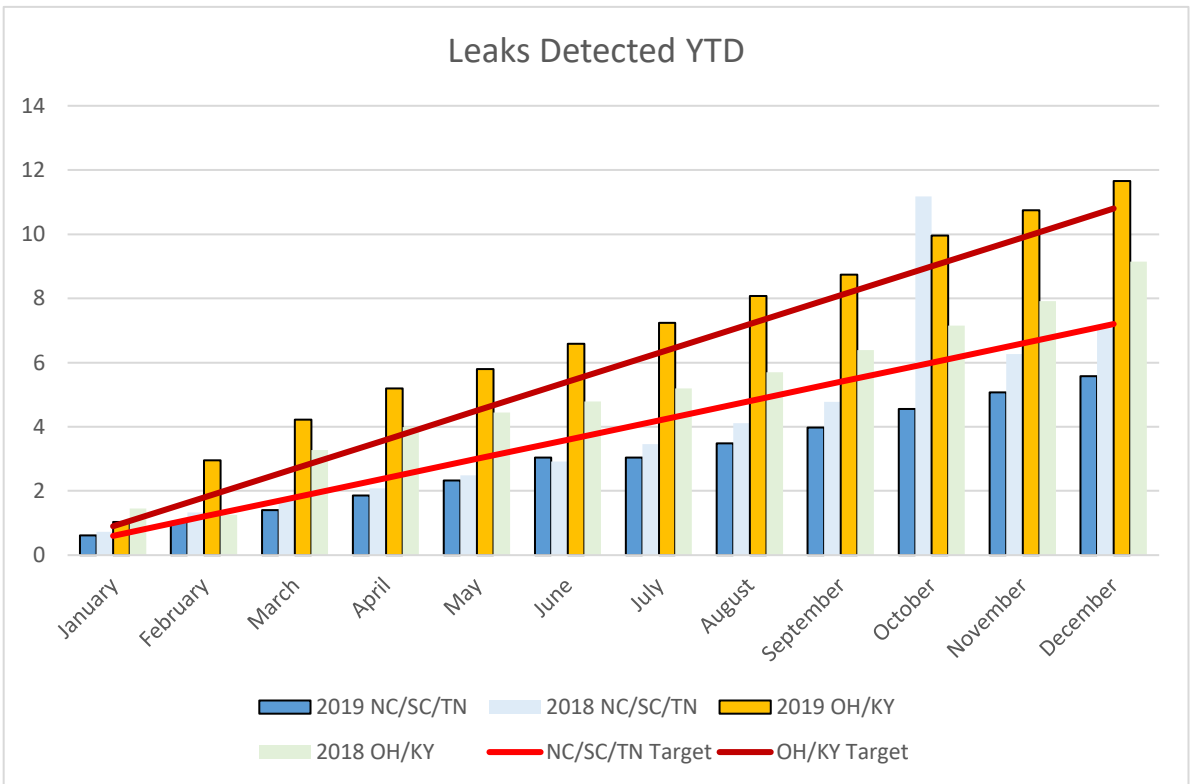


Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence

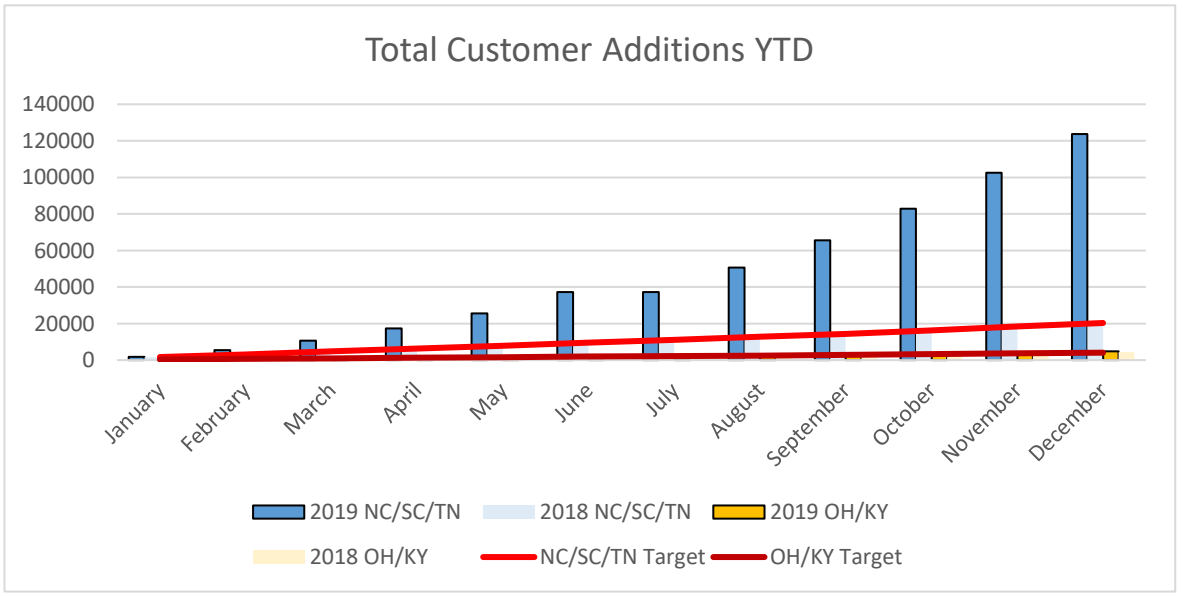


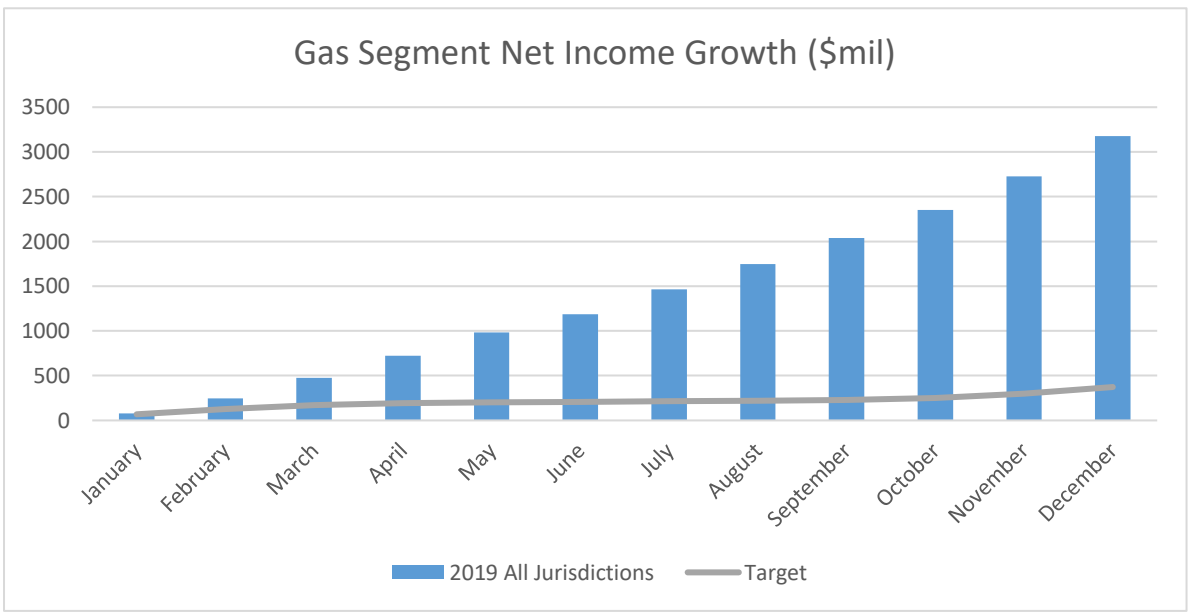


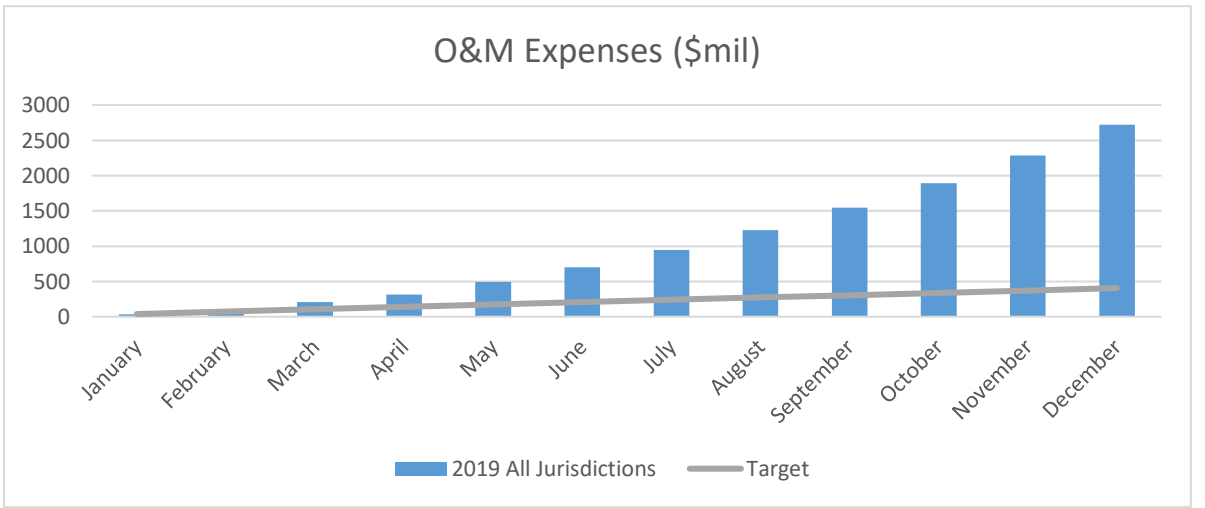
Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Operational Excellence



Gas Operations Performance Scorecard
Duke Ohio/Kentucky Gas & Legacy Piedmont Natural Gas
Category: Growth







		NC/SC/TN							OH/KY						
Metric Category	**Performance Metric**		**Maximum Acceptable Performance**		**YTD Target**		**Minimum Acceptable Performance**			**Maximum Acceptable Performance**		**YTD Target**		**Minimum Acceptable Performance**	
Customer	NPS - Residential	<-------	42.50%	<-------	40.50%	-------->	38.50%	-------->							
	NPS - SMB	<-------	46.10%	<-------	44.10%	-------->	42.10%	-------->				2019 targets are combined			
	ECHO Customer Service	<-------	94.00%	<-------	92.75%	-------->	92.75%	-------->				2019 targets are combined			
	Fastrack	N/A - No target tracked for 2019													
Operational Excellence	Employee TICR	<-------	0.89	<-------	1.1	-------->	1.42	-------->				2019 targets are combined			
	REEs	<-------	4	<-------	5	-------->	6	-------->				2019 targets are combined			
	Contractor Safety LAI	<-------	0	<-------	0	-------->	0	-------->				2019 targets are combined			
	Preventable Vehicle Incidents	<-------	60	<-------	70	-------->	80	-------->				2019 targets are combined			
	Damages per Locate	<-------	2.1	<-------	2.25	-------->	2.5	MTD				2019 targets are combined			
	Regulatory Findings	<-------	0	<-------	1	-------->	2	-------->				2019 targets are combined			
	Cybersecurity Performance Index	N/A - No target tracked for 2019													
	Natural Gas Outages / Reliability	<-------	0	<-------	2	-------->	4	-------->				2019 targets are combined			
	Emergency Response Time (mins)	<-------	32	<-------	34	-------->	36	-------->	<-------	33	<-------	35	-------->	37	-------->
	Work Order Completion (days)	<-------	2	0	4	-------->	5	Plan to	<-------	2	<-------	4	-------->	5	-------->
	Leaks Detected	<-------	6.2	<-------	7.2	-------->	8.2	-------->	<-------	9.6	<-------	10.8	-------->	12	-------->
Growth	Residential New Additions	<-------	17498	<-------	16332	-------->	15167	Develop	<-------	3262	<-------	3000	-------->	2738	-------->
	Residential Conversions	<-------	2429	<-------	2234	-------->	2039	-------->	<-------	759	<-------	700	-------->	641	-------->
	Commercial Additions	<-------	1883	<-------	1738	-------->	1593	-------->	<-------	383	<-------	350	-------->	317	-------->
	Total Customer Additions	<-------	21810	<-------	20304	-------->	18798	-------->	<-------	4404	<-------	4050	-------->	3696	-------->
	Gas Segment Net Income Growth	<-------	0-1	<-------	2	-------->	3-4	-------->				2019 targets are combined			
Employee	Diversity & Inclusion	TBD (Marie Broome)													
	Regrettable Attrition	TBD (Marie Broome)													
	Operational Excellence (NERC Issue)	TBD (Marie Broome)													
	Employee Engagement & Enablement	TBD (Marie Broome)													

Gas Operations Performance Scorecard
Natural Gas Business Unit
Metric Definitions

Customer	**NPS - Residential**	Net Promoter or Net Promoter Score (NPS) is a management tool that can be used to gauge the loyalty of a firm's customer relationships. It serves as an alternative to traditional customer satisfaction research and
	NPS - SMB	
	ECHO	"Every Customer Has Opinions" survey - average of 5 customer service questions weighted by number of surveys to calculate a customer satisfaction score
	Fastrack	The Fastrack program asks customers to rate their satisfaction with field work completed yesterday using a '0-10' scale. 'Net Satisfaction' scores are reported and calculated by subtracting the % Detractors (0-6) from the % Promoters (9&10)
Operational Excellence	**Employee TICR**	Number of employee OSHA recordable events x 200,000 / number of hours worked.
	REEs	Reportable Environmental Events are events resulting from Duke Energy operations that require notification to, or enforcement action by, a county, state or federal environmental regulatory agency. Category 1 REEs carry a fine greater than $10,000, and category 2 REEs carry a fine less than that amount. Category 3 REEs (near misses) are omitted.
	Contractor Safety LAI	Number of contractor serious injuries within control of the company or worker that resulted in certain types of injuries (See Health & Safety Department for more information).
	Preventable Vehicle Incidents	All preventable vehicle incidents.
	Damages per Locate	Number of damages per 1,000 line locate requests.
	Regulatory Findings	action. Metric will target no more than one fine greater than $10,000 or a corrective action that requires
	Cybersecurity Performance Index	The "CPI" is the total cybersecurity responsibility policy (CRP) violation rate per 100 workers in the groups outlined. The number is always provided in YTD.
	Natural Gas Outages / Reliability	Number of incidents where service was lost for more than 100 customers, excluding those incidents caused by third parties. Total number of outages with an outage defined as "non-third party caused affecting 100 or more customers" (*Note that a single outage affecting 500 or more customers wipes the metric to zero/no score).
	Emergency Response Time (mins)	Average time (minutes)it takes a Piedmont/Duke representative following an emergency notification to be on site either during working or non-working hours.

	Work Order Completion (days)	Average amount of time (days) it takes to complete a work order.
	Leaks Detected	Total Grade 1 and 2 leaks found per 100 miles (excluding excavation damage and above ground leaks).
Growth	**Total Customer Additions**	aggregate sum that includes Residential New Additions, Residential Conversions, and Commercial
	Gas Segment Net Income Growth	Net Income Growth reflects the total financial net gains for the Gas Segment, reported in millions of USD.
	O&M Expenses	Sum of all O&M Expenses for Natural Gas segment, reported in millions of USD.
Employee	**Diversity & Inclusion**	Measure calculates the percent representation of females and minorities in two separate calculations. Data is based upon what has been submitted/entered by employees into their Workday record. Total volume of full time + part time females divided the Population of the full time + part time headcount yields % representation. Minorities reflect any full time + part time employees that are NOT coded white or undefined divided by population.
	Regrettable Attrition	Calculated by capturing total terminations during specified time period. We do leverage a rolling 12 month period for consistency. For regrettable attrition, from total terms we eliminate anyone who left with severance, any retiree, any involuntary termination, any death or LTD term. Remainder is then divided by headcount.
	Operational Excellence (NERC Issue)	All terminations should be entered into the system 7 days prior to termination date if possible. But not later than the employee or contingent worker last day worked. Comparison is done by evaluating dates recorded of last day worked compared to date recorded in the system as entered. If greater than 1 day, flagged as late entry. NERC employees and contingents are flagged in the full population. Results are in the form of a count of late terminations.
	Employee Engagement & Enablement	Employee engagement surveys and scores are administered by a third party with results provided by tools to the levels of management with greater than 5+ employees responding. Pulse surveys may only receive results at an enterprise level. Specific questions are identified with the vendor and associated with the score calculation. Responses to these questions are then aggregated and a overall score calculated by the vendor using proprietary algorithms. Individual results are anonymous and held only by the vendor.
Service Provider Metrics	**SCADA Reliability**	Nomenclature for SCADA outages are (No of Outages) - (Total Minutes of Outage)

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-78. Page 46 of the 2019 Duke Energy 10k indicates that in determining the Goodwill Impairment Test it relies in part on application of the weighted average cost of capital (WACC) for each of its reporting units and that such ratios varied between 5.2% to 5.9%. With respect to this reference within the 10k respond to the following:

a. Identify the WACC applicable to the natural gas business unit in which Piedmont Tennessee resides.

b. Provide the calculation of the WACC referenced within the 10k that applies to the natural gas business unit in which Piedmont Tennessee resides.

c. Provide a thorough explanation for the theoretical distinction(s) between the WACC referenced within the Duke 10k and the WACC proposed within this docket.

RESPONSE:

a. 5.9%

b. See attachment.

c. The WACC referenced within the Duke Energy 10K is calculated for the purpose of estimating the fair value of Duke Energy's business units as discrete assets to an individual hypothetical buyer. The objective of the WACC proposed within this docket is to infer the market required return on equity for Piedmont Natural Gas based on market data reflecting the investment decisions of multiple investors valuing a minority interest in the Company's equity. Therefore, the intent and premise of the analyses are substantially different.

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In accordance with the Financial Accounting Standards Board, Duke Energy is required to perform periodic goodwill impairment tests. One step of that process is a market reconciliation, which compares Duke Energy's estimated fair value, as an asset discounted by a WACC, to the actual market value of its outstanding capital. Accounting Standards Codification (ASC) 820 notes:

> Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal (or most advantageous) market at the measurement date under current market conditions (that is, an exit price) regardless of whether that price is directly observable or estimated using another valuation technique. (1)

Thus, ASC 820 indicates that fair value is not linked directly to the current market value of a company's outstanding securities, but rather to an estimate of the subject entity's worth to a prospective buyer. Fair value reflects the value of Duke Energy's various operations to a prospective buyer through the purchase of the entire company as an asset, while the market value reflects the views of minority investors currently holding Duke Energy common equity. The circumstances of these distinct calculations are fundamentally different in nature and ultimately cannot be treated as equivalent.

(1) Accounting Standards Codification 820-10-35-9A

Name and Title of Preparer: Jordan Morgan, Treasury Director

Name and Title of Responsible Person: Jack Sullivan, Director - Corporate Finance and Investments, Assistant Treasurer

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-79. Page 111 of the 2019 Duke Energy 10k references $96 Million in Intersegment Revenues associated with the Gas Utilities and Infrastructure Business Segment. If any Intersegment revenues were generated associated with Piedmont Tennessee operations in 2019, provide the following information:

a. Identify the amount of 2019 Intersegment revenue generated which involved Piedmont Tennessee operations.

b. Provide a comprehensive description of how the Intersegment revenue was generated and the pricing of such Intersegment transactions were determined.

RESPONSE: N/A. The intersegment revenues referenced in the 10-K are not associated with Piedmont's Tennessee operations.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-80. To the extent Piedmont Tennessee incurred any 2019 Operating Expenses recorded on its books associated with the Pine Needle and Hardy Storage systems provide the following:

a. The charges incurred for each facility (if applicable) by month for 2019 along with the accounts charged.

b. Provide the monthly invoices generated which underly the Piedmont Tennessee charges.

RESPONSE: N/A. Piedmont's Tennessee operations do not incur any charges associated with Pine Needle and Hardy Storage.

Name and Title of Preparer: Nicole Aquilina, Accounting Manager II

Name and Title of Responsible Person: Bryan Manges, Director - Gas Utility & Infrastructure

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-81. Provide a copy of all Cash Working Capital Workpapers not previously provided in Excel format with all formulas intact.

RESPONSE: Please see the Company's response to MFR Item 12 for WorkingCapital_Adj for the workpaper in Excel format.

Name and Title of Preparer: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-82. Provide the underlying calculation and supporting workpapers for the $9,935,993 increase in Cash Working Capital identified as Requirement for Lead Lag within the Revenue Requirement Summary Schedule, which is identified as a hard-coded number.

RESPONSE: As explained in an email by Piedmont's counsel to the Consumer Advocate Division on August 3, 2020, the computation of the $9,935,993 increase in Cash Working Capital is provided in Exhibit PMN-2-CWC (p.1 of 3) accompanying Paul Normand's Lead Lag testimony filed in this proceeding.

Name and Title of Preparer: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Regulatory Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-83. Provide all available supporting evidence that by extending the length of time to pay bills by thirteen days in order to obtain the 'net discount' such tariff revision will translate to a thirteen day increase in the revenue lag calculation.

RESPONSE: By extending the payment terms by 13 days for Piedmont Tennessee, the terms would be the same in Tennessee as it is in Piedmont North Carolina. In the Company's last NC rate case, the collection lag for the test period (the 12 months ended Dec 31, 2018) was 33.00 days. This compares to the collection lag computed for Piedmont Tennessee which was 30.59 days for the 12 months ended Dec 31, 2019, which includes the 13 days added for the change in payment terms. Both calculations were performed in a similar manner.

The Company believes the 30.59 days is reasonable given this comparison.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-84. Has Piedmont North Carolina implemented the increase in payment terms to the 25 days as proposed in Ms. Powers testimony? If so, provide the date of implementation and provide documentation identifying the incremental change in the revenue payment lag resulting from such tariff change, if such calculation exists.

RESPONSE: Piedmont's North Carolina residential customers have received payment terms of 25 days for many years. Piedmont's North Carolina non-residential customers have received payment terms of 15 days for many years. Piedmont has been unable to confirm the exact date of implementation, although it has confirmed that these terms have been in effect since at least November 1, 2005. Since Piedmont has been unable to determine the date of implementation, Piedmont does not have documentation identifying an incremental change in the revenue payment lag.

Name and Title of Preparer: Pia Powers, Managing Director - Gas Rates & Regulatory

Name and Title of Responsible Person: Pia Powers, Managing Director - Gas Rates & Regulatory

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-85. Provide a copy of all regulatory orders supporting the deferral and rate recovery associated with environmental costs.

RESPONSE: Amortized recovery of Piedmont's previous unamortized deferred environmental expense balances was granted in Docket Nos. 99-00994, 03-00313 and 11-00144 (Piedmont general rate cases). See attachments for the Orders in those dockets, as well as the Order in Docket No. 92-16160 which authorized deferral treatment for Piedmont's environmental expenses.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Gas Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

BEFORE THE TENNESSEE PUBLIC SERVICE COMMISSION

Nashville, Tennessee

December 21, 1992

IN RE: PIEDMONT NATURAL GAS COMPANY - REQUEST FOR APPROVAL OF SPECIAL ACCOUNTING FOR ENVIRONMENTAL ASSESSMENT AND CLEANUP COSTS

Docket No. 92-16160

ORDER

By letter dated December 10, 1992, Piedmont Natural Gas Company has requested Commission approval of special accounting for future costs associated with environmental assessments and cleanups.

Federal and state agencies have imposed environmental control requirements relating primarily to air emissions, wastewater discharges, and solid, toxic and hazardous waste management. Piedmont is attempting to ensure that its operations meet applicable environmental regulations and standards.

Piedmont requests the Commission's immediate attention to this matter so that it can receive an unqualified opinion from its independent auditors for the recently ended October 31, 1992, fiscal year. If there is a material financial matter that investors need to be apprised of regarding a company's financial statement, the company must disclose this fact and the Independent Auditor is obligated to issue a "qualified" opinion on the financial statements calling attention to this matter. Of

course, this could be a material event that could adversely affect Piedmont's financial position. Apparently, the Commission's approval to record this as an asset gives the Independent Auditor sufficient evidence that the Commission will give consideration to allowing Piedmont to recover this cost from rate payers and therefore allow the Independent Auditor to issue an "unqualified" opinion.

Under normal ratemaking and accounting rules, costs such as these are not recorded as an asset. Instead, they are recorded as an expense and flowed through to net income. Expenditures are considered assets if they benefit future periods such as plant purchases. If they are for past or current services, which is the category these cleanup costs fall in, they are considered expenses, and not recorded as assets. However, regulators have the power to create assets by promising a utility it will allow it to recover an expense that is related to a past period. Although the Company is not requesting the Commission to rule on the fairness of passing these costs to rate payers, authorizing it to be set up as an asset could inappropriately be viewed as a step in that direction unless complete disclosure is made as to the basis of the Commissions decision.

The Staff pointed out this could be $1,000 liability, a $100 million liability, or some other figure. The Commission has no evidence that this cost should be borne by the rate payer and therefore recorded as an asset. This issue would normally be

addressed in a rate case where the Commission would have evidence on the size of the liability, who is responsible for the liability and the fairness of passing this cost on to the rate payers. The Commission at that time would have evidence as to the amount of the costs and would give due consideration to the merits of the arguments for and against recording this cost as an asset and passing all or part of it on to rate payers.

This matter was presented to the Commission by the Staff during a specialy called meeting held on Monday, December 21, 1992. The Staff recommended two options for handling Piedmont's request.

Staffs first preference is for Piedmont to be authorized to account for this cost as an operating expense under the existing accounting rules. Staff argued that at this time, when the Company's actual expenses are small, there is no compelling reason to postpone paying those expenses. (The Company could maintain side records and capture any cost incurred in connection with this contingent liability between now and the time it files a rate case and make its argument to the Commission at that time as to why it should be allowed to recover this cost from rate payers). When and if a significant liability materializes, as part of a rate case or otherwise, the Commission could review the evidence and arguments at that time and make a decision to the appropriateness of deferring the cost as an asset and passing the cost on to the rate payers.

Staff's second option is for the commission to authorize the accounting sought by Piedmont, provided Piedmont would explain that the basis for the commission's authorization was to provide sufficient evidence to issue an unqualified opinion and appropriately disclose the regulatory status of this regulatory created asset versus other assets in the financial statements. The disclosure defining the regulatory created asset for this expense should include the following:

> "Unlike other assets appearing on the balance sheet, authorizing past cleanup expense as a regulatory asset does not necessarily mean the Commission will authorize the Company to recover this from future rate payers. It simply says the Commission will consider this in a rate case when the Commission will have evidence of the amount of the cleanup cost, who is responsible for the cleanup cost and the fairness of passing this cost on to rate payers."

By fully disclosing the basis for authorizing this asset, we believe the second option will accomplish the needs of all parties. Piedmont will receive an unqualified opinion and readers of the financial statements will have sufficient information to understand the status of the deferred-cleanup expense-asset versus other assets on the financial statements. We, therefore, approve Piedmont's request subject to the following or similar language being included in Piedmont's financial statements:

> "Authorizing past cleanup expenses as a regulatory asset does not mean the Commission will authorize the Company to recover all or part of these expenses from future rate payers. It simply says

18412
18445

the Commission will consider this in a rate case when the Commission will have evidence concerning the total amount of the cleanup cost, who is responsible for the cleanup cost, and the fairness of passing this cost on to ratepayers."

Based upon the Staff recommendation, the Commission approves Piedmont's request with the accompanying disclosure language.

IT IS SO ORDERED.

CHAIRMAN

COMMISSIONER

COMMISSIONER

ATTEST:

EXECUTIVE DIRECTOR

BEFORE THE TENNESSEE PUBLIC SERVICE COMMISSION
Nashville, Tennessee
JANUARY 7, 1993

IN RE: PIEDMONT NATURAL GAS COMPANY -- REQUEST FOR APPROVAL OF SPECIAL ACCOUNTING FOR ENVIRONMENTAL ASSESSMENT AND CLEANUP COSTS.

DOCKET NO. 92-16160

DISSENTING OPINION

This matter is before the Tennessee Public Service Commission upon the request of Piedmont Natural Gas for Commission approval of special accounting for future costs associated with environmental assessments and cleanups for the purpose of avoiding a qualified opinion from its independent auditor in the published financial statements to Piedmont's stockholders. The majority of the Commission approved creating a regulatory asset for these expenses with the following disclosures:

> Authorizing past cleanup expenses as a regulatory asset does not mean the Commission will authorize the Company to recover all or part of these expenses from future rate payers. It simply says the Commission will consider this in a rate case when the Commission will have evidence concerning the total amount of the cleanup cost, who is responsible for the cleanup cost, and the fairness of passing this cost on to ratepayers.

In a memo to the Commissioners, dated December 18, 1992, the Director of the Utility Rate Division set forth two possible alternatives for booking these costs: (a) recording them as an expense which is the normal accounting procedure or (b) "the less desirable alternative" -- recording an asset with the disclosure

that the cost is not necessarily recoverable through rates. I agree with the Staff's preference in this matter i.e., that the Company should be required to account for this cost as an operating expense under the existing accounting rules. Currently, the Company's actual cleanup costs are small, consequently there is no reason to postpone recognizing those expenses. When and if a significant liability materializes, as a part of a rate case or otherwise, the Commission should review the evidence and arguments at that time and make a decision regarding the appropriateness of deferring the cost as an asset and passing the cost on to the ratepayers.

Further, I am concerned about giving the Company any signal that they may be able to recover these expenses from ratepayers at some future date, especially since our legal staff has not had an opportunity to thoroughly research the legal ramifications of denying the recovery of a regulatory asset created by the Commission.

For the foregoing reasons the request of Piedmont Natural Gas to record environmental assessment and cleaning costs as a deferred asset should be denied.

STEVE HEWLETT, CHAIRMAN

ATTEST:

PAUL ALLEN, EXECUTIVE DIRECTOR

BEFORE THE TENNESSEE REGULATORY AUTHORITY AT

NASHVILLE, TENNESSEE

July 18, 2000

IN RE:	)	
	)	
APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF ITS RATES AND CHARGES, THE APPROVAL OF REVISED TARIFFS AND THE APPROVAL OF REVISED SERVICE REGULATIONS	)	**DOCKET NO. 99-00994**

ORDER APPROVING APPLICATION

This matter came before the Tennessee Regulatory Authority (the "Authority") at a Hearing held on June 5, 2000 upon the Application of Nashville Gas Company (the "Company" or "Nashville Gas"), an operating division of Piedmont Natural Gas Company, Inc. ("Piedmont") for a general rate increase, the approval of revised tariffs, and the approval of revised service regulations.

Background

On December 30, 1999, Nashville Gas filed an application for an adjustment of its rates and charges, the approval of revised tariffs, and the approval of revised service regulations. In that filing, Nashville Gas sought an increase in its annual revenues of $10,687,612. After the discovery of certain errors in the Company's filing, the most notable of which were related to the computation of construction work in progress and accumulated depreciation, Nashville Gas's attrition period revenue deficiency was reduced by $620,063 to $10,067,549.

At a regularly scheduled Authority Conference held on January 11, 2000, the Authority voted to suspend the application for ninety (90) days. At a regularly scheduled Authority Conference held on February 1, 2000, the Directors appointed the General Counsel or his designee to act as Pre-Hearing Officer in this proceeding for the purpose of hearing preliminary matters and setting a procedural schedule to completion.

On February 11, 2000, the Consumer Advocate Division of the Office of the Attorney General (the "Consumer Advocate") filed a "Complaint or Petition to Intervene" in this proceeding. On April 6, 2000, the Consumer Advocate's petition for intervention was granted by the Pre-Hearing Officer without objection from Nashville Gas. By letter dated April 6, 2000, Nashville Gas agreed to extend the date at which rates may be placed into effect under bond from June 30, 2000 to July 31, 2000 in order to accommodate the agreed procedural schedule.[1]

On April 27, 2000, Associated Valley Industries Group ("AVI") filed a petition for intervention. On May 9, 2000, Ford Motor Company ("Ford") and Visteon Corporation ("Visteon") filed a joint petition for intervention. No objections being raised by the parties, on May 18, 2000, the Pre-Hearing Officer issued an order granting both petitions for intervention.

On May 18, 2000, Nashville Gas and the Consumer Advocate filed a Joint Motion for Approval and Implementation of Stipulation (the "Stipulation") in which they stated that they had resolved all known disputed issues in this case and had agreed to certain specified adjustments to revenues, expenses, net operating income, net operating income for return, rate base, and return on rate base. These adjustments reduce the Company's additional revenue

[1] The Hearing was set for June 5-8 to allow Nashville Gas to respond to Authority data requests and because certain witnesses for Nashville Gas would not be available earlier.

requirements from $10,687,612[2] to $4,944,000. The Company filed supplemental testimony and the Consumer Advocate filed an affidavit in support of the Stipulation.

On May 25, 2000, Ford and Visteon advised the Authority that they were in support of the rate design as to Special Contract customers and did not oppose the stipulation as to other matters. In support of their position, Ford and Visteon filed the affidavit of James Mulholland, Manager of Natural Gas Programs for Ford Motor Land Services Corporation. On June 2, 2000, the acting Pre-Hearing Officer issued an order establishing a schedule for the orderly conduct of the Hearing. All parties agreed to an order, which was entered on June 5, 2000, permitting the Authority Staff to ask questions of witnesses during the Hearing.

Nashville Gas's Hearing

On June 5, 2000, a Hearing was held in this matter. The Company presented the direct and supplemental testimony of Bill R. Morris, Chuck W. Fleenor, Ware F. Schiefer, and Dr. Donald A. Murry. The Consumer Advocate presented the affidavit and testimony of Daniel W. McCormac. Ford and Visteon presented the affidavit and testimony of James Mulholland. A representative of AVI stated that AVI did not wish to offer testimony or cross-examine witnesses and that AVI supported the Stipulation.

After testimony and questions from the Directors and the Authority Staff, the Authority approved the Stipulation except for the provision of the Stipulation relative to a tracking mechanism for "Special Contract Customers." Since the Authority must review and approve all special contracts, it is difficult to determine what benefit would be derived from advance approval of the special contract incentive mechanism. By sharing any revenue deviations from

[2] As noted above, $10,687,612 was the amount initially requested by the Company in its Application. After correction of a miscalculation, this figure was reduced to $10,067,549.

current levels, with ten percent (10%) going to Nashville Gas and ninety percent (90%) to other customers, the mechanism purports to provide an incentive for Nashville Gas to negotiate the highest possible rate for special contracts. In theory, ratepayers benefit from having to make up a smaller contribution loss than would be otherwise required if the special contract customer negotiated a lower rate or went to another supplier. In the past, and in the absence of any such "tracking mechanism," Nashville Gas has claimed to have negotiated the highest possible rate with special contract customers in its efforts to prevent by-pass. This being the case, it is unclear what would be achieved by giving the Company further supposed incentives under the tracking mechanism. Locking Nashville Gas into a 10% sharing of any loss with respect to special contract customers would limit the Authority's ability to allocate responsibility for revenue changes in a manner that is appropriate to the particular circumstances surrounding the consideration of a special contract at the time it is submitted to the Authority for approval. For these reasons, the Authority excluded approval of the incentive mechanism for special contract customers without prejudice.

The Authority also approved the Stipulation with a final proviso. The Authority's decision permitting the amortization of deferred pension costs does not indicate in any way that the Authority is abandoning the rationale for the treatment of pension costs as announced in its Orders of February 19, 1997 and June 9, 1997 in Docket No. 96-00977. In that proceeding, the Authority responded to the fact that the Company's pension plan could drop below a fully funded position before the Company's next rate filing by allowing the establishment of a deferred regulatory asset and future recovery. Nevertheless, the Authority has not abandoned the basic and sound regulatory goal of matching current expenses with current ratepayers. To the extent that the Company's future pension expenses continue to surpass fully funded levels, the

Authority will act appropriately to match current expenses with current ratepayers, notwithstanding its actions here.

All parties agreed to waive the condition of the Stipulation that required the Stipulation to be approved in whole.

Authority Consideration of Rate Increases

The Authority considers petitions seeking adjustments of rates and charges pursuant to Tenn. Code Ann. § 65-5-203, which provides:

> 1) that the Authority shall have the power upon written complaint, or upon its own initiative, to hear and determine whether the increase, change or alteration being sought by a public utility is just and reasonable;
>
> 2) that the burden of proof to show that the increase, change or alteration is just and reasonable shall be on the public utility making the same; and
>
> 3) that in determining whether such increase, change or alteration is just and reasonable, the Authority shall take into account the safety, adequacy and efficiency or lack thereof of the service or services furnished by the public utility.

The Stipulation

In the Stipulation, the Company and the Consumer Advocate agreed, and the Authority approved, that the Company should be permitted to:

> (1) increase its rates to produce additional revenues of $4,944,000 effective July 1, 2000;
>
> (2) recover 100% of its prudently incurred Liquefied Natural Gas power costs through its periodic Actual Cost Adjustment filings;
>
> (3) implement the revised rates attached to this Order as Schedule I effective July 1, 2000;
>
> (4) use the gas costs embedded in the proposed rates and set forth in Schedule II, attached to this Order, in future true-ups of gas costs under the Company's Purchase Gas Adjustment (PGA);

(5) use the "R" values, base load factors, and heat factors set forth in Schedule III, attached to this Order, in future rate adjustments under the Company's Weather Normalization Adjustment;

(6) implement the revised tariffs attached to this Order as Schedule IV effective July 1, 2000;

(7) implement the revised Service Regulations, including the main extension policy contained therein, attached to this Order as Schedule V, effective July 1, 2000; and

(8) amortize the previously established regulatory asset for deferred pension costs of $1,016,093 over a period of five years, beginning with the effective date of the rates approved herein.

Rate Increase

Schedule VI, attached to this Order, contains the Rate Base, Operating Income at Present Rates, Earned Rate of Return from Present Rates, Fair Rate of Return, Required Operating Income to Produce the Fair Rate of Return, Operating Income Deficiency, Gross Revenue Conversion Factor and Revenue Deficiency agreed upon by the Company and the Consumer Advocate in the Stipulation. The Authority has carefully reviewed each of these items and, based upon the testimony and supporting documentation, concludes that each is fair and reasonable and should be approved. The Authority further concludes that in order to permit the Company to earn the return determined to be just and reasonable, the Company should be allowed to increase its rates by $4,944,000. Further, the Authority has determined that this rate increase should become effective beginning with service rendered on and after July 1, 2000.

Rate Design and Tariff Changes

In his pre-filed direct and supplemental direct testimony, Chuck Fleenor testified that he designed the Company's proposed rates using a cost of service study of existing rates along with traditional rate design principles and the desire to provide additional services to the ratepayers.[3]

[3] Pre-Filed Direct Testimony of Chuck Fleenor, December 30, 1999, p. 4.

The traditional rate design principles considered by Mr. Fleenor included value of service, the need to avoid discrimination among classes of service, system load equalization, and revenue stability.[4] He testified that his main objective was to develop a design and structure that will enable the Company to continue to adapt to the many changes occurring in the natural gas industry and to recommend rate levels that more properly reflect the cost and value of service.[5]

In the Stipulation, the parties agreed to a rate increase of $4,944,000, or $5,743,612 less than requested by the Company in the Application. The parties also agreed that approximately 97% of the reduction in the rate increase should be reflected in rates for residential customers and the remainder in rates for small general service customers. As a result, residential rates will increase by 1.91%, small general service rates will increase by 3.97%, and industrial rates will increase by 8.38%.

The Company also filed to reduce the fixed gas costs included in its PGA by $2,418,299 to reflect a reduction in demand for gas from its suppliers as a result of the Company's renegotiations of its supplier contracts. The Company proposed to place this PGA reduction in effect simultaneously with the margin rate increase. The net effect of the PGA reduction and the margin rate increase approved herein is an increase in residential rates of 0.71%, an increase in small general service rates of 2.84%, and an increase of 2.67% for industrial rates.

The stipulated rates are set forth as Schedule I, attached to this Order, and are supported by Mr. Fleenor in his supplemental direct testimony.[6] After careful consideration, the Authority concludes that the stipulated rates are fair and reasonable to all classes of customers and will

[4] Pre-Filed Direct Testimony of Chuck Fleenor, December 30, 1999, p. 5.
[5] Id., p. 7.
[6] Pre-Filed Supplemental Direct Testimony of Chuck Fleenor, May 18, 2000, pp. 1-2.

permit the Company a reasonable opportunity to earn the return on the rate base previously found to be fair and reasonable.

The Company also proposed certain changes to its tariff language to permit the Company to respond to existing competitive conditions. Mr. Fleenor testified that market and regulatory changes over the years have caused certain language in the Company's existing tariffs to become outdated and in need of revision.[7] He testified that existing tariffs were designed for and intended to apply to the provision of monopolistic utility services to customers who have no alternative delivery system for natural gas.[8] Since competitive gas services are available to customers today, the Company proposes to amend the applicability section of all of its rate schedules to state that they apply only to full requirement natural gas customers.[9] In addition, the Company proposes to clarify language and correct typographical errors that occur in several rate schedules.[10] The Company also proposes to modernize and strengthen the "Unauthorized Gas" provisions of its tariffs to make them more reflective of the current volatile daily gas market and to provide a greater economic disincentive for abuse.[11]

No party has objected to the proposed tariff changes, and the Authority finds them to be fair and reasonable.

Service Regulations

Nashville Gas also proposed changes to its Service Regulations. The Company proposed to change its policy to allow main extension investments on those projects that produce a positive net present value (NPV) over the life of the project. The discount rate in the NPV

[7] Pre-Filed Direct Testimony of Chuck Fleenor, December 30, 1999, p. 9.
[8] Id.
[9] Id.
[10] Id.
[11] Id.

calculation is equal to the overall allowed rate of return in the Company's last general rate case. Mr. Morris testified[12] that the proposed methodology is the same methodology that has been approved for Piedmont by both the North Carolina Utilities Commission and the Public Service Commission of South Carolina and is similar to the policy approved by the Authority for Chattanooga Gas Company in Docket No. 96-01174.[13] The Company also proposed to eliminate the current preference given to Company employees under the existing main extension policy.

Because the Company no longer adds gas air conditioning customers, the Company proposed to eliminate the provision for 200 feet of free service line for the installation of gas air conditioning and heating which is currently included in its service line policy. In addition, the Company proposed a change in its service line policy to provide for 100 feet of free service line for the installation of one major gas appliance, where no main extension is required. An additional 50 feet of free service line would be allowed for the installation of each additional minor appliance, such as an outdoor grill or fireplace logs. Finally, the Company proposed to increase its reconnect fee from $35 to $50, and to eliminate the entire section pertaining to mobile homes.

The Authority carefully reviewed the proposed changes to the Company's Service Regulations and concluded that they are fair and reasonable.

Special Contract Customers

The Company proposed and the Stipulation provided for the implementation of a tracking mechanism for "Special Contract Customers," as explained in the pre-filed direct testimony of Bill R. Morris.[14] Under this proposal, the Company would share in any difference between

[12] Pre-Filed Direct Testimony of Bill R. Morris, December 30, 1999, p. 12.
[13] Authority Order of June 2, 1999.
[14] Pre-Filed Direct Testimony of Bill R. Morris, December 30, 1999, pp. 4-5.

annual revenues actually received from the Special Contract Customers and the existing Special Contract revenue on a 90%/10% basis. The Company states that such a mechanism would give it an incentive to maximize increases and minimize reductions in Special Contract revenue because of its potential 10% share in increases or reductions. In support of this tracking mechanism, the Company argued that the mechanism would provide the Company with an incentive to maximize its revenues from the Special Contract Customers to the benefit of all other customers. Nevertheless, in view of the Company's past practice of maximizing these revenues without an incentive, the Authority did not find a need for such a mechanism at this time. Further, the Authority will consider approval of all special contracts on a case-by-case basis, considering all relevant evidence, including the need for any recovery or "sharing" of any revenue changes, at the time the contract is submitted for approval. Prior approval of such a "sharing" or "tracking" arrangement, which may not meet the future needs of the Company or the public, is not necessary in this situtation. Therefore, the Authority excluded without prejudice the approval of the incentive mechanism for special contract customers.

IT IS THEREFORE ORDERED THAT:

1. The rates filed by Nashville Gas Company on December 31, 1999 are hereby denied;

2. The rates attached to this Order as Schedule I are hereby approved to be effective July 1, 2000, and the existing rates for the "Special Contract Customers" shall continue in effect until further order of the Authority;

3. The allocation of fixed pipeline demand costs for future changes in rates under the Company's Purchased Gas Adjustment as set forth in Schedule II attached to this Order are hereby approved to be effective July 1, 2000;

4. The Weather Normalization Adjustment factors attached to the Order as Schedule III are hereby approved to be effective July 1, 2000;

5. The tariffs attached to this Order as Schedule IV are hereby approved to be effective July 1, 2000;

6. The Service Regulations attached to this Order as Schedule V are hereby approved, to be effective July 1, 2000;

7. The Company is authorized to recover 100% of its prudently incurred Liquefied Natural Gas power costs through its periodic Actual Cost Adjustment filings;

8. The Company is authorized to amortize the regulatory asset for deferred pension costs of $10,016,093 over a period of five (5) years beginning with the effective date of the rates approved herein;

9. The Company's request to implement a tracking mechanism for "Special Contract Customers" is excluded from approval of the Stipulation without prejudice;

10. Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within fifteen (15) days from and after the date of this

11. Any party aggrieved with the Authority's decision in this matter has the right to judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Division, within sixty (60) days from and after the date of this Order.

Melvin J. Malone, Chairman

H. Lynn Greer, Jr., Director

Sara Kyle, Director

ATTEST:

K. David Waddell, Executive Secretary

Nashville Gas Company
Schedule of Proposed Margin Rates
Per Therm

Rate Class	Margin Rates
Residential	
Customer Charge/Per month	$ 8.00
Winter	0.29884
Summer	0.26255
Air Conditioning	0.22255
Backup Service Demand Charge	0.534506
Small General Service	
Customer Charge/Per month	$ 22.00
Winter	0.34839
Summer	0.31233
Air Conditioning	0.27266
Backup Service Demand Charge	0.534506
Large General Service	
Demand Charge	$ 0.80000
First 15,000 Therms	0.08918
Next 25,000 Therms	0.08195
Next 50,000 Therms	0.05904
Over 90,000 Therms	0.02530
Interruptible General Service	$ 300.00
First 15,000 Therms	0.08034
Next 25,000 Therms	0.07382
Next 50,000 Therms	0.05319
Over 90,000 Therms	0.02280
Firm Transportation Service	
Demand Charge	$ 0.80000
First 15,000 Therms	0.08918
Next 25,000 Therms	0.08195
Next 50,000 Therms	0.05904
Over 90,000 Therms	0.02530
Interruptible Transportation Service	
Customer Charge/Per month	$ 300.00
First 15,000 Therms	0.08034
Next 25,000 Therms	0.07382
Next 50,000 Therms	0.05319
Over 90,000 Therms	0.02280
Sales For Resale	
Demand Charge	$ 0.80000
Commodity	0.07000

Nashville Gas Company
Schedule of Fixed Gas Cost Rates
Per Therm

Rate Class	Fixed Cost Rate	Apportionment Percentage
Residential		
Customer Charge/Per month		
Winter	0.04898	49.211%
Summer	0.04898	49.211%
Air Conditioning	0.04898	49.211%
Backup Service Demand Charge		
Small General Service		
Customer Charge/Per month		
Winter	0.04442	30.661%
Summer	0.04442	30.661%
Air Conditioning	0.04442	30.661%
Backup Service Demand Charge		
Large General Service		
Demand Charge	0.63730	8.976%
First 15,000 Therms	0.00292	0.309%
Next 25,000 Therms	0.00240	0.066%
Next 50,000 Therms	0.00169	0.001%
Over 90,000 Therms	0.00000	0.000%
Interruptible General Service		
First 15,000 Therms	0.02992	0.512%
Next 25,000 Therms	0.02940	0.402%
Next 50,000 Therms	0.02869	0.290%
Over 90,000 Therms	0.02700	0.068%
Firm Transportation Service		
Demand Charge	0.63730	7.660%
First 15,000 Therms	0.00292	0.194%
Next 25,000 Therms	0.00240	0.111%
Next 50,000 Therms	0.00169	0.025%
Over 90,000 Therms	0.00000	0.000%
Interruptible Transportation Service		
Customer Charge/Per month		
First 15,000 Therms	0.00292	0.208%
Next 25,000 Therms	0.00240	0.214%
Next 50,000 Therms	0.00169	0.186%
Over 90,000 Therms	0.00000	0.000%
Sales For Resale		
Demand Charge	0.63730	0.900%
Commodity	0.00200	0.006%

Piedmont Natural Gas Company, Inc.
Calculation of "R" Values for WNA Computations
Nashville Gas Rate Case

		Residential	Commercial
Fixed Gas Costs	($/therm)	0.04898	0.04442
Commodity	($/therm)	0.29209	0.29209
"R" Value	($/therm)	0.29884	0.34839
HSF	(therms/DDD)	0.18769	0.79321
BL	(therms/mo.)	13.018	126.066

NASHVILLE GAS COMPANY
665 Mainstream Drive
Nashville, Tennessee 37228
A Division of Piedmont Natural Gas Company
TRA Rate Schedule No.1

RATE SCHEDULE NO. 1
Residential Service

AVAILABILITY
Available within the Company's service area to any full requirements single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered where the Company's distribution mains are suitable for supplying the desired service.

MARGIN RATE	Winter (November-March)	Summer (April-October)
Customer Charge (per month)	$8.00	$8.00
Commodity Charge (per therm)	$.29884	$.26255
Backup Service Demand Charge (per therm of input per month)	$.534506	$.534506

AIR CONDITIONING RIDER
A Residential Customer who uses gas for summer air conditioning shall be billed at a rate of $.04 per therm less than that listed above for all gas consumed over 50 therms per month. This discount shall apply to all gas used during the billing months of June through October.

MONTHLY CUSTOMER CHARGE
A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer charge will be billed from the date of initial service until service is terminated at the Customer's request. In the case of temporary discontinuance of service there will be a reconnect charge of $50.00 to be billed at the time the gas service is reinstated.

BACKUP SERVICE
When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating.

Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

WEATHER NORMALIZATION ADJUSTMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 13, "Weather Normalization Adjustment Rider".

NASHVILLE GAS COMPANY
665 Mainstream Drive
Nashville, Tennessee 37228
A Division of Piedmont Natural Gas Company
TRA Rate Schedule No.2

RATE SCHEDULE NO. 2
Small General Service

AVAILABILITY

Gas service under this Rate Schedule is available to any full requirements non-residential Customer whose maximum usage during any month of the 12-month period ended the 31st day of March was not more than 15,000 therms. Availability under this Rate Schedule for new Customers will be based on reasonably anticipated usage. A Customer under this Rate Schedule will be eligible to be transferred to Rate Schedules 3, 4, 7F or 7I if the Customers' usage is 110% or more of the minimum required by such rate schedule. Any such transfers will be effective June 1 of each year.

MARGIN RATE	Winter (November-March)	Summer (April-October)
Customer Charge (per month)	$22.00	$22.00
Commodity Charge (per therm)	$.34839	$.31233
Backup Service Demand Charge (per therm of input per month)	$.534506	$.534506

AIR CONDITIONING RIDER

A Small General Service Customer who uses gas for summer air conditioning shall be billed at a rate of $.04 per therm less than that listed above for all gas consumed over 500 therms per month. This discount shall apply to all gas used during the billing months of June through October.

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer charge will be billed from the date of initial service until service is terminated at the Customer's request. In the case of temporary discontinuance of service there will be a reconnect charge of $50.00 to be billed at the time the gas service is reinstated.

BACKUP RATE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating.

Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

WEATHER NORMALIZATION ADJUSTMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 13, "Weather Normalization Adjustment Rider".

RATE SCHEDULE NO. 3
Large General Sales Service

AVAILABILITY

Gas service under this Rate Schedule is available to any full requirements non-residential Customer whose usage during any month of the 12-month period ended the 31st day of March was in excess of 15,000 therms. Availability under this Rate Schedule for new Customers will be based on reasonably anticipated usage. An existing Customer may also qualify for service under this Rate Schedule based upon reasonably anticipated usage by adding incremental load either by the installation of additional equipment or by increasing hours of operation. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. A Customer will be transferred from this Rate Schedule to Rate Schedule No.2 if the Customers' usage is 90% or less of the minimum required by this Rate Schedule. Any such transfers will be effective June 1 of each year.

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 9 concurrent with service provided under the Rate Schedule. Subject to the requirements set forth above, a Customer may elect to discontinue service under this Rate Schedule and receive service under Rate Schedule No.7F by giving written notice to the Company prior to March 1 of any year. Proper notice having been provided, the Customer shall discontinue service under this Rate Schedule effective the first June 1 following the notice.

MARGIN RATE

Demand Charge (per therm of billing demand)	$.80000
Commodity Charge (per therm)	
1st Step (0-15,000 therms)	$.08918
2nd Step (15,001-40,000 therms)	$.08195
3rd Step (40,001-90,000 therms)	$.05904
4th Step (Over 90,000 therms)	$.02530

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the monthly demand charge.

BILLING DEMAND

The billing demand shall be determined as follows:

A Customer's billing demand determinant shall be the highest daily usage during the period from November 1 to March 31 of the previous winter period as metered and reported to the Company by the telemetering equipment installed by the Company. Changes to the Customer's billing demand determinant will become effective May 1 of each year. The per unit demand charge may be adjusted from time to time to reflect rate changes, including, but not limited to, a general change in system rates or a change in pipeline capacity charges billed to the Company.

For Customers commencing initial gas service under this Rate Schedule and who do not have a consumption history from other services provided by the Company, the billing demand determinant shall be computed by multiplying the month of highest consumption for the period to date by six percent (6%). If a Customer has received gas service from the Company prior to receiving service under this rate schedule, but does not have daily telemetered records to determine peak day usage as described above, the Company shall determine a billing demand based upon the highest monthly level of consumption during the previous winter period multiplied by six percent (6%).

SERVICE AGREEMENTS

All Customers purchasing gas under this Rate Schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Rate Schedule No.6, "Schedule for Limiting and Curtailing Service".

NASHVILLE GAS COMPANY
665 Mainstream Drive
Nashville, Tennessee 37228
A Division of Piedmont Natural Gas Company
TRA Rate Schedule No.4

RATE SCHEDULE NO. 4
Interruptible General Sales Service

AVAILABILITY

Gas service under this rate schedule is available **ON AN INTERRUPTIBLE BASIS** to any full requirements non-residential Customer whose usage during any month of the 12-month period ended the 31st day of March was in excess of 15,000 therms when adjusted for curtailment and cycle length. Availability under this rate schedule for new Customers will be based on reasonably anticipated usage. An existing Customer may also qualify for service under this Rate Schedule by adding incremental load either by the installation of additional equipment or by increasing hours of operation. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. A Customer will be transferred from this Rate Schedule to Rate Schedule 2 if the Customers' usage is 90% or less of the minimum required by this Rate Schedule. Any such transfers will be effective June 1 of each year.

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 9 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may elect to discontinue service under this Rate Schedule and receive service under Rate Schedule No.7I by giving written notice to the Company prior to March 1 of any year. Proper notice having been provided, the Customer shall discontinue service under this Rate Schedule effective the first June 1 following the notice.

Customers purchasing gas pursuant to this schedule shall maintain, in useable condition, alternate-fuel facilities with ample on-site alternate fuel capability for supplying 100% of the establishment's gas requirements during periods of gas interruption or curtailment. Such interruption or curtailment shall be immediately effective upon verbal or written notification by the Company, and Customer shall refrain from using gas until permitted to do so by the Company. It is understood and agreed that the Company will have the right to suspend gas service without further notice to the Customer in the event Customer fails to curtail Customer's use of gas in accordance with the Company's notice of curtailment.

MARGIN RATE

Customer Charge (per month)	$300.00	
Commodity Charge (per therm)		
1st Step (0-15,000 therms)		$.08034
2nd Step (15,001-40,000 therms)		$.07382
3rd Step (40,001-90,000 therms)		$.05319
4th Step (Over 90,000 therms)		$.02280

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer Charge will be billed from the date of initial service until service is terminated at the Customer's request.

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

SERVICE SCHEDULE NO. 6
Schedule for Limiting and Curtailing Service

This Service Schedule defines the types of curtailment that the Company may invoke from time to time due to the occurrence of extreme weather conditions, operating conditions or force majeure events, and describes the process and procedures to be followed in the implementation of gas service restrictions.

DISTRIBUTION PRESSURE CURTAILMENTS

Due to extreme weather conditions, operating conditions or force majeure events as defined in the Nashville Gas Company Service Regulations, Rules and Regulations Governing Supply and Consumption of Gas, or the demands of the Company's firm Customers as the same may effect the Company's ability to provide interruptible service, the Company may experience localized pressure deficiencies. During such times and within the areas affected, the Company will curtail service to interruptible Customers served under Rate Schedule No. 4, Rate Schedule No. 9, or Rate Schedule 7I, by priority of their margin contribution to the Company (curtailing Customers with the lowest margin rate first) until the pressure situation can be alleviated. In the unlikely event that further interruption is required, the Company will proceed with curtailment by margin contribution considering end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SUPPLY OR CAPACITY RELATED CURTAILMENTS

In situations when supply and capacity services contracted by the Company are not sufficient to meet the full requirements of Customers desiring sales services from the Company, the Company will first curtail service to interruptible sales Customers receiving service under Rate Schedule No. 4 by priority of their margin contribution to the Company. Customers receiving discounted sales service under Rate Schedule No. 9 will also be curtailed according to the discounted rates. The Company reserves the right at the Company's discretion to purchase quantities being delivered to the Company by Customers under Rate Schedule 7I at market prices in order to serve Customers without operable alternative fuel capability. In the unlikely event that further interruption is required, the Company will proceed with curtailment by margin contribution considering end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

EMERGENCY SERVICE

The Company will make every reasonable effort to deliver plant protection volumes to industrial and commercial Customers that do not have standby fuel systems sufficient to prevent damage to facilities or danger to personnel, or to Customers that find it impossible to continue operations on the Customer's standby or alternate energy source as a result of a bona fide existing or threatened emergency. This includes the protection of such existing material in process that would otherwise be destroyed, or deliveries required to maintain plant production. All emergency gas service is of a discretionary nature and implies no present or future obligation of the Company to any Customer to provide such service on either a temporary or continuing basis. Deliveries of gas hereunder shall be made pursuant only to advance operating arrangements between the Company's authorized personnel and the Customer and shall be subject to curtailment and interruption at any time should the Company deem it necessary.

RATE FOR EMERGENCY SERVICE

If the Company has authorized the Customer to consume limited quantities of emergency gas as provided in the above paragraph, then all gas consumed by the Customer will be at a rate of $1.00 per therm plus the higher of two gas commodity indices, "Monthly Contract" and "Daily Price", until otherwise notified that either (1) further gas sales will be under the Customer's regular rate schedule or (2) complete curtailment is unavoidable and that further gas sales will be considered unauthorized. "Monthly Contract" shall be defined as the monthly contract index price for the applicable calendar month as published in Gas Daily under the designation, "Monthly Contract Index" and indicated specifically under "Citygates" for Tenn. Zone 6 (delivered)". "Daily Price" shall be defined as the daily price for gas defined by Gas Daily as stated in the "Daily Price Survey", "Citygates", "Tenn. Zone 6 (delivered)", "Midpoint" price. For days of consumption when the Gas Daily is not published, the Gas Daily price shall equal the price as published on the nearest subsequent day by Gas Daily. Revenues realized from emergency service transactions will be credited to the Actual Cost Adjustment (ACA) account as recovery of gas costs.

UNAUTHORIZED OVER RUN PENALTY

If at any time a Customer exceeds specified contract entitlements or if during any curtailment period, any affected Customer takes, without the Company's advance written approval, a volume of natural gas in excess of the curtailment period quantity entitlement applicable to such Customer, said volume shall constitute an unauthorized over run volume. For each therm of such unauthorized over run volume taken by such Customer, such Customer shall pay to the Company a rate of $1.50 per therm plus the higher of two gas commodity indices, "Monthly Contract" and "Daily Price". "Monthly Contract" shall be defined as the monthly contract index price for the applicable calendar month as published in Gas Daily under the designation, "Monthly Contract Index" and indicated specifically under "Citygates" for Tenn. Zone 6 (delivered)". "Daily Price" shall be defined as the daily price for gas defined by Gas Daily as stated in the "Daily Price Survey", "Citygates", "Tenn. Zone 6 (delivered)", "Midpoint" price. For days of consumption when the Gas Daily is not published, the Gas Daily price shall equal the price as published on the nearest subsequent day by Gas Daily. The Customer shall be liable for the above charges together with and in addition to any incremental charges or assessments (including, but not limited to penalties) by the interstate pipeline during the time of the unauthorized usage by such Customer . The payment of a penalty for unauthorized over run volumes shall not under any circumstances be considered as giving any such Customer the right to take unauthorized over-run volumes, nor shall such payment be considered as a substitute for any other remedies available to the Company or any other Customer against the offending Customer for failure to adhere to its obligations under the provisions of this Rate Schedule. Revenues realized from unauthorized over run penalties will be credited to the Actual Cost Adjustment (ACA) account as recovery of gas costs.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

RATE SCHEDULE NO. 7F
Firm Transportation Service

AVAILABILITY

Gas service under this Rate Schedule is available to any full requirements non-residential Customer whose usage during any month of the 12-month period ended the 31st day of March was in excess of 15,000 therms. Availability under this Rate Schedule for new Customers will be based on reasonably anticipated usage. An existing Customer may also qualify for service under this Rate Schedule based upon reasonably anticipated usage by adding incremental load either by the installation of additional equipment or by increasing hours of operation. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. A Customer will be transferred from the Rate Schedule to Rate Schedule 2 if the Customers' usage is 90% or less of the minimum required by this Rate Schedule. Any such transfers will be effective June 1 of each year.

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 9 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may elect to discontinue service under this Rate Schedule and receive service under Rate Schedule 3 by giving written notice to the Company prior to March 1 of any year. Proper notice having been provided, the Customer shall discontinue service under this Rate Schedule effective the first June 1 following the notice.

APPLICABILITY AND CHARACTER OF SERVICE

Transportation service is available under this Rate Schedule to any qualified Customer connected to the Company's system who has obtained an independent supply of natural gas and has arranged to have this supply delivered to one of the Company's existing delivery points for transportation by the Company to the Customer's facilities.

The Company will deliver gas previously transported by a connected pipeline for the Customer's account under this Rate Schedule on a day-to-day basis in accordance with the Customer's scheduled and confirmed nominations, subject to such maximum allowable daily deliveries as may be specified in the Gas Service Contract. The Company reserves the right to suspend service on any day when, in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. The Company reserves the right to limit, allocate, or direct third party gas nominations among the interstate pipelines serving the Company's distribution system, when, in the Company's sole opinion, such action is necessary to maintain the operational integrity of the system.

Receipts and deliveries of gas hereunder shall be at uniform rates of flow with no significant fluctuations or imbalance. Any imbalances shall be corrected by the Customer, insofar as practicable, during the month in which they occur. Customer may adjust its daily nominations during a month in order to correct any accumulated imbalance and maintain a monthly balance, subject to the operating limitations of the Company. The Company reserves the right to limit the amount of such imbalances to avoid operating problems and to comply with balancing requirements of any pipeline transporting gas hereunder. Customer will be responsible for any imbalance charges assessed by the pipeline in connection with any gas transported by the Company under this Rate Schedule. The Company reserves the right to reduce nominations when, in the judgment of the Company, such action is necessary to reduce or eliminate operational problems. Company will use its best efforts to notify the Customer or the Customer's agent before proceeding with a unilateral reduction and will notify Customer of any reduction to Customer's nomination that has been instituted by the Company. The Company reserves the

right to initiate Standby Sales Service, described below, when, in the judgement of the Company, such action is necessary to reduce or eliminate operational problems resulting from the gas imbalances of the Customer. The Company will use its best efforts to notify the Customer or the Customer's agent before initiating Standby Sales Service.

By 10:30am central time four business days prior to the beginning of each month, the Customer shall inform the Company of its a) nomination of the daily quantity of gas to be transported for such month, and b) choice of pipeline for transportation for such month. If the Customer does not provide a timely nomination to transport gas provided by a party other than the Company, the Customer will have requested Standby Sales Service provided herein by default. By 10:30am central time six business days prior to the beginning of each month, the Customer must inform the Company of the nominating agent for gas to be transported.
Changes to nominations for gas transportation within the month are due by 10:30am central time on the day prior to gas flow.

BALANCING

It shall be the Customer's responsibility to maintain a daily and monthly balance with its transporting pipelines to avoid any assessment of penalties against the Company. If the Company is assessed a penalty by a Customer's transporting pipeline, the Company shall have the right to pass-through all such penalties to the Customer to the extent the Customer is responsible for causing the Company to be assessed such penalties.

MONTHLY IMBALANCE RESOLUTION

Any differences between the quantities delivered to the Company's city gate facilities for the account of the Customer for the month, and the quantities consumed by the Customer as metered for the month, shall be the monthly imbalance. Unless the Company and Customer agree to correct imbalances in kind, this imbalance shall be resolved monthly by "cashing out" the imbalance as they are known to exist at that time. If the Customer consumes more gas than it has delivered to the Company, the Customer will be deemed to be "short" by the amount of the deficiency, and the Company will sell gas to the Customer in an amount equal to the deficiency and at a price equal to the highest Weighted Index Price for any week beginning in the calendar month as published in *Natural Gas Week* plus the Tennessee Gas Pipeline FT-A charges inclusive of all surcharges and fuel times the premium percentage corresponding to the percentage of the deficiency listed in the table below. If the Customer consumes less gas than it has delivered to the Company, the Customer will be deemed to be "long" by the amount of the surplus, and the Company will buy the amount of the surplus by paying the Customer a price equal to the lowest Weighted Index Price for any week beginning in the calendar month as published in *Natural Gas*

Week plus the Tennessee Gas Pipeline FT-A charges inclusive of all surcharges and fuel times the discount percentage corresponding to the percentage of the surplus listed in the table below.

Percentage of the Imbalance	Short (Premium)	Long (Discount)
Equal to or less than 5%	100%	100%
Over 5% & equal to or less than 10%	115%	85%
Over 10% & equal to or less than 15%	130%	70%
Over 15% & equal to or less than 20%	140%	60%
Over 20%	150%	50%

"The Weighted Index Price" shall be derived from the prices published in *Natural Gas Week* in the table Spot Prices on Interstate Pipeline Systems for the following pipeline designations and weighted by the corresponding percentages set forth below:

Tennessee Gas Pipeline Co. Zone 0:South Texas	X	19.47%[1]
+		
Tennessee Gas Pipeline Co. Zone 1: South Louisiana	X	73.69%[1]
+		
Columbia Gulf Transmission Co.: Rayne, La.	X	6.84% [1]

The Company will collect gross receipts tax on the incremental gas related charges.

Any difference between the actual cost of gas incurred by the Company and the Index price as defined in the previous paragraph will be accounted for in the Actual Cost Adjustment account in a manner consistent with Rule No. 1220-4-1-12 of the TRA Rules and Regulations. Increments or decrements which may result from the PGA adjustments will not apply to the cash-out of imbalances.

AGENCY AUTHORIZATION FORM

A Customer may authorize an agent to act on its behalf with respect to the nominations, imbalance resolution, and/or billing under this Rate Schedule by executing an Agency Authorization Form in the form attached to this Rate Schedule. To the extent that the Agent appointed by the Customer is common to other Customers of the Company, the Company will permit such Agent to aggregate all such qualifying Customers' transportation quantities for purposes of administering service to such Agent. Once a Customer has designated an agent, the agent is then authorized to act on behalf of that Customer and as such, the agent can be considered as the Customer in all references contained within this Rate Schedule. The Customer may not change agents within the calendar month without the permission of the Company. All agents must utilize the electronic means made available by the Company in order to submit nominations. The Company may recover all costs incurred in providing the agent access to the electronic bulletin board.

STANDBY SALES SERVICE

At the option of the Customer, an election may be made monthly to receive Standby Sales Service from the Company under this Rate Schedule for delivery to the Customer at the Company's city gate. The Customer will also receive Standby Sales Service as a default if the Customer or the Customer's agent fails to submit a timely and valid nomination for transportation service. In addition to paying the Monthly Standby Index Price set forth below for Standby Sales Service hereunder, the Customer will utilize the transportation services and incur the charges otherwise applicable under this Rate Schedule to cause such gas supplies to be delivered to the Customer's meter. The price which the Customer shall pay for the gas supplied under this paragraph will be the Monthly Standby Index Price defined as follows: "The weighted average index price for the applicable month as published in the first *Natural Gas Week* for such month in the table Spot Prices on Interstate Pipeline Systems in the column labeled "Bid Week", for:

Tennessee Gas Pipeline Co. Zone 0:South Texas	X	19.47%[1]
+		
Tennessee Gas Pipeline Co. Zone 1: South Louisiana	X	73.69%[1]
+		
Columbia Gulf Transmission Co.: Rayne, La.	X	6.84%[1]

1 These percentages are the ratio of actual test period purchases for these two pipelines determined in the Company's most recent general rate case.

If the Customer nominates transportation service hereunder and purchases gas supplies from a third party supplier, and such Customer's consumption exceeds actual deliveries to the Company from such third party supplier to the point where operational problems are created for the Company, then the Company shall have the right, at it sole discretion, to initiate Standby Sales Service to the Customer. The price for such service shall be the same as set forth above except when the Company is required by such imbalance shortfall to purchase incremental volumes of gas supplies. In this case the Customer receiving Standby Sales Service will pay the higher of (on a daily basis) the Monthly Standby Index Price or the Daily Standby Index Price defined as follows:

The midpoint daily index price as published in Gas Daily for the day of consumption as stated in the "Daily Price Survey", for the "Tennessee 500 Leg". For days of consumption when the Gas Daily is not published, the Gas Daily price shall equal the price as published on the nearest subsequent day by Gas Daily.

Applicable firm transportation tariff commodity charges, fuel and any other surcharges as defined in the above transporters' FERC approved tariffs will be added to the above standby index prices. The Company will collect gross receipts tax on the incremental gas related charges.

Any difference between the actual cost of gas incurred by the Company and the Index price as defined in the previous paragraph will be accounted for in the Actual Cost Adjustment account in a manner consistent with Rule No. 1220-4-1-12 of the TRA Rules and Regulations. Increments or decrements which may result from the PGA adjustments will not apply to the standby index prices.

MARGIN RATE

Demand Charge (per therm of billing demand)	$.80000
Commodity Charge (per therm)	
1st Step (0-15,000 therms)	$.08918
2nd Step (15,001-40,000 therms)	$.08195
3rd Step (40,001-90,000 therms)	$.05904
4th Step (Over 90,000 therms)	$.02530

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the monthly demand charge multiplied by the billing demand determined as described below.

BILLING DEMAND

The billing demand shall be determined as follows:

Customer billing demand determinate shall be the highest daily usage during the period from November 1 to March 31 of the previous winter period as metered and reported to the Company by the telemetering equipment installed by the Company. Changes to the Customer's billing demand determinate will become effective May 1 of each year. The per unit charge may be adjusted from time to time to reflect rate changes, including, but not limited to, a general change in system rates or a change in pipeline capacity charges billed to the Company. For Customers commencing initial gas service under this Rate Schedule and who do not have a consumption history from other services provided by the Company, the billing demand determinate shall be based upon a reasonable assumption of usage considering the connected load. If a Customer has received gas service from the Company prior to receiving service under this Rate Schedule but does not have daily telemetered records to

determine peak day usage as described above , the Company shall determine a billing demand based on the highest monthly level of consumption during the previous winter period multiplied by six percent (6%).

SERVICE AGREEMENTS

All Customers receiving service under this Rate Schedule shall be required to execute the Company's standard contracts and/or service applications and shall be subject to the Company's Rules and Regulations as filed with and approved by the Tennessee Regulatory Authority (TRA).

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for transportation service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with the Rules, Regulations and Orders of the TRA and the Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, the TRA Rules and Regulations, Orders of the TRA, and the Laws of the State of Tennessee.

SERVICE CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

AGENCY AUTHORIZATION FORM
RATE SCHEDULE NO.7F

DATE_____

CUSTOMER_____
NAME OF FACILITY **ACCOUNT NUMBER(S)**

_____

AGENT_____

AGENT CONTACT_____PHONE #_____

This is to advise **Nashville Gas Company** that _____**(Customer)** has authorized _____**(Agent)** to act on its behalf for the following transactions:

_____nominations, _____imbalance resolution, _____ billing,

of gas for the above listed account(s). Nashville Gas Company is hereby authorized to deal with the Agent directly, and by signature below, the Customer and the Agent understand that they are responsible, jointly and severally for any amounts due Nashville Gas Company under this Rate Schedule which are not paid by agent on these accounts. Customer will provide Nashville Gas Company with a revised "AGENCY AUTHORIZATION FORM" at least six (6) business days prior to changing Agents of the accounts designated.

AUTHORIZED SIGNATURE_____
FOR THE CUSTOMER

AUTHORIZED SIGNATURE_____
FOR THE AGENT

Please Print
AGENT'S NAME_____TITLE_____
PHONE #_____FAX #_____
MAILING ADDRESS_____

Please submit to: End User Transportation
Nashville Gas Company
A Division of Piedmont Natural Gas Company
P O Box 33068
Charlotte, NC 28233
Fax # _704 365-8740

RATE SCHEDULE NO. 7I
Interruptible Transportation Service

AVAILABILITY

Gas service under this Rate Schedule is available ON AN INTERRUPTIBLE BASIS to any full requirements non-residential Customer whose usage during any month of the 12-month period ended the 31st day of March was in excess of 15,000 therms. Availability under this Rate Schedule for new Customers will be based on reasonably anticipated usage. An existing Customer may also qualify for service under this Rate Schedule based upon reasonably anticipated usage by adding incremental load either by the installation of additional equipment or by increasing hours of operation. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. A Customer will be transferred from this Rate Schedule to Rate Schedule 2 if the Customers' usage is 90% or less of the minimum required by this Rate Schedule. Any such transfers will be effective June 1 of each year.

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule No. 9 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may elect to discontinue service under this Rate Schedule and receive service under Rate Schedule No.4 and/or 10 by giving written notice to the Company prior to March 1 of any year. Proper notice having been provided, the Customer may discontinue service under this Rate Schedule effective the first June 1 following the notice.

Customers receiving services under this Rate Schedule shall maintain, in useable condition, alternate-fuel facilities with ample on-site alternate fuel capability for supplying 100% of the establishment's gas requirements during periods of gas interruption or curtailment. Such interruption or curtailment shall be immediately effective upon verbal or written notification by the Company, and Customer shall refrain from using gas until permitted to do so by the Company. It is understood and agreed that the Company will have the right to suspend gas service without further notice to the Customer in the event Customer fails to curtail Customer's use of gas in accordance with the Company's notice of curtailment.

APPLICABILITY AND CHARACTER OF SERVICE

Transportation service is available under this Rate Schedule to any qualified Customer connected to the Company's system who has obtained an independent supply of natural gas and has arranged to have this supply delivered to one of the Company's existing delivery points for transportation by the Company to the Customer's facilities.

The Company will deliver ON AN INTERRUPTIBLE BASIS gas previously transported by a connected pipeline for the Customer's account under this Rate Schedule on a day-to-day basis in accordance with the Customer's scheduled and confirmed nominations. The Company reserves the right to suspend service on any day when, in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. The Company reserves the right to

limit, allocate, or direct third party gas nominations among the interstate pipelines serving the Company's distribution system, when, in the Company's sole opinion, such action is necessary to maintain the operational integrity of the system.

Receipts and deliveries of gas hereunder shall be at uniform rates of flow with no significant fluctuations or imbalance. Any imbalances shall be corrected by the Customer, insofar as practicable, during the month in which they occur. Customer may adjust its daily nominations during a month in order to correct any accumulated imbalance and maintain a monthly balance, subject to the operating limitations of the Company. The Company reserves the right to limit the amount of such imbalances to avoid operating problems and to comply with balancing requirements of any pipeline transporting gas hereunder. Customer will be responsible for any imbalance charges assessed by the pipeline in connection with any gas transported by the Company under this Rate Schedule. The Company reserves the right to reduce nominations when, in the judgment of the Company, such action is necessary to reduce or eliminate operational problems. Company will use its best efforts to notify the Customer or the Customer's agent before proceeding with a unilateral reduction and will notify Customer of any reduction to Customer's nomination that has been instituted by the Company.

By 10:30am central time four business days prior to the beginning of each month, the Customer shall inform the Company of its a) nomination of the daily quantity of gas to be transported for such month, and b) choice of pipeline for transportation for such month. If the Customer does not provide a timely nomination to transport gas , the Customer will not be entitled to receive gas service. By 10:30am central time six business days prior to the beginning of each month, the Customer must inform the Company of the nominating agent for gas to be transported.

Changes to nominations for gas transportation within the month are due by 10:30am central time on the day prior to gas flow.

Notwithstanding the above, if a supplier interrupts its sales service to Customer being transported hereunder, and such interruptions by the supplier occur within a month, Customer may reschedule alternative gas supplies which may be available to Customer subject to: a) normal daily nomination and confirmation deadlines and procedures b) any operational limitations of the Company and c) the availability of interruptible transportation service hereunder.

BALANCING

It shall be the Customer's responsibility to maintain a daily and monthly balance with its transporting pipelines to avoid any assessment of penalties against the Company. If the Company is assessed a penalty by a Customer's transporting pipeline, the Company shall have the right to pass-through all such penalties to the Customer to the extent the Customer or Customer's agent is responsible for causing the Company to be assessed such penalties.

MONTHLY IMBALANCE RESOLUTION

Any differences between the quantities delivered to the Company's city gate facilities for the account of the Customer for the month, and the quantities consumed by the Customer as metered for the month, shall be the monthly imbalance. Unless the Company and Customer agree to correct imbalances in kind, this imbalance shall be resolved monthly by "cashing out" the imbalance as they are known to exist at that time. If the Customer consumes more gas than it has

delivered to the Company, the Customer will be deemed to be "short" by the amount of the deficiency, the Company will sell gas to the Customer in an amount equal to the deficiency and at a price equal to the highest Weighted Index Price for any week beginning in the calendar month as published in *Natural Gas Week* plus the Tennessee Gas Pipeline FT-A charges inclusive of all surcharges and fuel times the premium percentage corresponding to the percentage of the deficiency listed in the table below. If the Customer consumes less gas than it has delivered to the Company, the Customer will be deemed to be "long" by the amount of the surplus, and the Company will buy the amount of the surplus by paying the Customer a price equal to the lowest Weighted Index Price for any week beginning in the calendar month as published in *Natural Gas Week* plus the Tennessee Gas Pipeline FT-A charges inclusive of all surcharges and fuel times the discount percentage corresponding to the percentage of the surplus listed in the table below.

Percentage of the Imbalance	Short (Premium)	Long (Discount)
Equal to or less than 5%	100%	100%
Over 5% & equal to or less than 10%	115%	85%
Over 10% & equal to or less than 15%	130%	70%
Over 15% & equal to or less than 20%	140%	60%
Over 20%	150%	50%

"The Weighted Index Price" shall be derived from the prices published in *Natural Gas Week* in the table Spot Prices on Interstate Pipeline Systems for the following pipeline designations and weighted by the corresponding percentages set forth below:

Tennessee Gas Pipeline Co. Zone 0:South Texas	X	19.47%[1]
+		
Tennessee Gas Pipeline Co. Zone 1: South Louisiana	X	73.69%[1]
+		
Columbia Gulf Transmission Co.: Rayne, La.	X	6.84% [1]

The Company will collect gross receipts tax on the incremental gross gas related charges

Any difference between the actual cost of gas incurred by the Company and the Index prices defined above will be accounted for in the Actual Cost Adjustment account in a manner consistent with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations. Increments or decrements which may result from the PGA adjustments will not apply to the cash-out mechanism.

AGENCY AUTHORIZATION FORM

A Customer may authorize an agent to act on its behalf with respect to the nominations, imbalance resolution, and/or billing under this Rate Schedule by executing an Agency Authorization Form in the form attached to this Rate Schedule. To the extent that the Agent appointed by the Customer is common to other Customers of the Company, the Company will permit such Agent to aggregate all such qualifying Customers' transportation quantities for

1 These percentages are the ratio of actual test period purchases for these two pipelines determined in the Company's most recent general rate case.

purposes of administering service to such Agent. Once a Customer has designated an agent, the agent is then authorized to act on behalf of that Customer and as such, the agent can be considered as the Customer in all references contained within this Rate Schedule. The Customer may not change agents within the calendar month without the permission of the Company. All agents must utilize the electronic means made available by the Company in order to submit nominations. The Company may recover all costs incurred in providing the agent access to the electronic bulletin board.

MARGIN RATE

Customer Charge (per month)	$300.00
Commodity Charge (per therm)	
1st Step (0-15,000 therms)	$.08034
2nd Step (15,001-40,000 therms)	$.07382
3rd Step (40,001-90,000 therms)	$.05319
4th Step (Over 90,000 therms)	$.02280

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge.

SERVICE AGREEMENTS

All Customers receiving service pursuant to this Rate Schedule shall be required to execute the Company's standard contracts and/or service applications and shall be subject to the Company's Rules and Regulations as filed with and approved by the Tennessee Regulatory Authority (TRA).

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for transportation service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchase gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with the Rules, Regulations and Orders of the TRA and the Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, the TRA Rules and Regulations, the Orders of the TRA, and the Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is interruptible and is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

AGENCY AUTHORIZATION FORM
RATE SCHEDULE NO.7I

DATE_____

CUSTOMER_____
NAME OF FACILITY ACCOUNT NUMBER(S)

_____

AGENT_____

AGENT CONTACT_____PHONE #_____

This is to advise **Nashville Gas Company** that _____ **(Customer)** has authorized _____**(Agent)** to act on its behalf for the following transactions:

_____nominations, _____imbalance resolution, _____ billing,

of gas for the above listed account(s). Nashville Gas Company is hereby authorized to deal with the Agent directly, and by signature below, the Customer and the Agent understand that they are responsible, jointly and severally for any amounts due Nashville Gas Company under this Rate Schedule which are not paid by agent on these accounts. Customer will provide Nashville Gas Company with a revised "AGENCY AUTHORIZATION FORM" at least six (6) business days prior to changing Agents of the accounts designated.

AUTHORIZED SIGNATURE_____
FOR THE CUSTOMER

AUTHORIZED SIGNATURE_____
FOR THE AGENT

Please Print
AGENT'S NAME_____TITLE_____
PHONE #_____FAX #_____
MAILING ADDRESS_____
_____

Please submit to: End User Transportation
Nashville Gas Company
A Division of Piedmont Natural Gas Company
P O Box 33068
Charlotte, NC 28233
Fax # __704-365-8740

RATE SCHEDULE NO. 9
Special Availability Service

AVAILABILITY

Gas service under this rate schedule is available to any TRA Rate Schedule No. 3, 4, 7F, or 7I, Customer when the Company has gas supplies or services that it cannot sell at its established fixed rates where the Company's distribution mains are suitable for supplying the desired service. On such occasions, the opportunity is lost to the Company and its Customers. This Rate Schedule is designed to permit the Company to sell such gas and services at special rates for the purpose of enabling the Company to compete with alternative fuels and services available for use by its Customers.

Gas service under this Rate Schedule is available on a limited term basis to Customers who are connected to the Company's distribution system and would otherwise qualify for commercial and industrial sales or transportation service.. Gas service may be provided under this Rate Schedule only in the event that the Company has available supplies or services that cannot competitively be provided under other rate schedules. Service under this Rate Schedule is temporary and the Company has the right to discontinue such service. Gas service under this rate schedule will be curtailed prior to service under any other rate schedule.

In the event a Customer has zero consumption during any billing month, this tariff will not apply and service shall be rendered pursuant to the Company's regular rate schedules for the class of service indicated for the purpose of determining a minimum bill and qualifying provisions.

BASE RATE

The Customer shall pay the Company for all gas supplied or services provided under this schedule at a predetermined rate negotiated prior to delivery for limited term periods up to seven consecutive months.

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this Rate Schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the above stated net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in

accordance with Rule No. 1220-4-1-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated base rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use priority as specified by the Federal Energy Regulatory Commission (FERC), impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service."

TREATMENT OF NEGOTIATED MARGIN LOSSES

Margin losses under this rate schedule shall be recovered by the Company through the Company's Actual Cost Adjustment (ACA) as provided in the Company's Purchased Gas Adjustment (PGA) Rider (TRA Service Schedule No. 11).

NASHVILLE GAS COMPANY
665 Mainstream Drive
Nashville, Tennessee 37228
A Division of Piedmont Natural Gas Company
TRA Rate Schedule No. 10

RATE SCHEDULE NO. 10
Resale Service

AVAILABILITY
Sales for Resale Service is available under this rate schedule to any qualified local distribution company who purchases natural gas for the purpose of reselling same, where the Company's distribution mains are suitable for supplying the desired service.

MARGIN RATE

Demand Charge (per therm of billing demand)	$.80000
Commodity Charge (per therm)	$.07000

MONTHLY MINIMUM BILL
The minimum monthly bill shall be the monthly demand charge.

BILLING DEMAND
Demand determinants shall be those agreed to in the contract.

SERVICE AGREEMENTS
All customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with

Rule No. 1220-4-7 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgement as to the available gas supply, customer's load factor or use pattern, end use priority as specified by the Federal Energy Regulatory Commission (FERC), impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the curtailment provisions contained within TRA Schedule No. 6, "Schedule for Limiting and Curtailing Service".

NASHVILLE GAS COMPANY
665 Mainstream Drive
Nashville, Tennessee 37228
A Division of Piedmont Natural Gas Company
TRA Rate Schedule No. 13

SERVICE SCHEDULE NO. 13
Weather Normalization Adjustment (WNA) Rider

I. Provision for Adjustment

The base rates per therm (100,000 Btu) for gas service set forth in any rate schedules utilized by the Authority in determining normalized test period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment".

The Weather Normalization Adjustment will be applicable for bills rendered on and after November 1 and continuing through the final billing cycle in March of each year.

II. Definitions

For the purposes of this Rider:

"Authority" means the Tennessee Regulatory Authority.

"Relevant Rate Order" means the final order of the Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Authority specifically prescribing or fixing the factors and procedures to be used in the application of this Rider.

III. Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment shall be computed to the nearest one-hundredth cent per therm by the following formula:

$$WNA_i = R_i \quad * \quad \frac{(HSF_i(NDD-ADD))}{(BL_i + (HSF_i \times ADD))}$$

Where:

I = any particular rate schedule or billing classification within any particular rate schedule that contains more than one billing classification.

WNA_i = Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per therm.

R_i = weighted average base rate (base rate less any embedded gas cost) of temperature sensitive sales for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

HSF_i = heat sensitive factor for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

NDD = normal billing cycle heating degree days utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

ADD = actual billing cycle heating degree days.

BL_i = base load sales for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

IV. Filing with Authority

The Company will file as directed by the Authority (a) a copy of each computation of the Weather Normalization Adjustment, (b) a schedule showing the effective date of each such Weather Normalization Adjustment, and a schedule showing the factors or values derived from the Relevant Rate Order used in calculating such Weather Normalization Adjustment.

2nd Revised Addendum to TRA Service Schedule No. 13

NASHVILLE GAS COMPANY
WNA Components

	Residential	Commercial
"R" Value:	0.29884	0.34839
Heat Sensitivity Factor	0.18769	0.79321
Base Load:	13.018	126.066

Piedmont Natural Gas Company

Nashville Gas Company Service Regulations

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Nashville Gas Company Service Regulations

Section 1 – GENERAL SERVICE POLICY OF NASHVILLE GAS

Nashville Gas (hereinafter referred to as "the Company") will make free service calls, within certain broad guidelines, around-the-clock on customer appliances connected to our mains. Those service requests requiring immediate attention will be answered as soon as possible. Those of less urgent nature will be answered on a scheduled basis according to the workload. In either case, the Company will make every effort to answer each customer's call promptly and to leave all appliances operating at maximum efficiency.

Free Services (1220-4-5-.06(iii))

The Company provides the following services at no charge to the customer during normal working hours (Mon - Fri, 8am - 5pm, excluding Holidays):

- Install gas meters and regulators for new customers
- Turn-on, turn-off, & service gas meters
- Check for gas leaks
- Investigate the possible presence of carbon monoxide
- Cut off pilots
- Disconnect appliances (disconnect & cap existing pipe only)
- Food Service equipment service including leveling, adjusting, or calibrating
- Diagnostic time or time to provide an estimate for jobbing work
- Quotes for appliance installation
- The first light-up and service call of the heating season on central furnaces (a flat charge applies for each additional light-up)
- Gaslight turn-on and re-lighting
- Service leased water heaters
- Service appliances other than central heating systems or gas air conditioners (no parts needed) including:
  - Service calls to diagnose problems
  - Check gas pressure
  - Adjust burners
  - Clean air mixers
  - Light pilots
  - Clean & adjust pilots
  - Examine flue connections & check draft
  - Check and calibrate thermostats & controls
  - Check appliance wiring & other electrical components
- Service central heating systems including floor furnaces and unit heaters

including:
  - Service calls to diagnose problems
  - Gas and air adjustments on burners and pilot assemblies
  - Adjustments of controls and thermostats
  - Minor electrical repairs that do not require materials
- Service Arkla, Bryant, and other gas-fired air conditioners including:
  - Service calls to diagnose problems
  - Gas and air adjustments on burners and pilot assemblies
  - Checks of controls and thermostats
  - Pumping of water-cooled units to maintain operation
  - Purging of non-condensables from air-cooled units

Note: When an appliance is not operating, every effort will be made to answer the call without delay, and in most circumstances, on the same day. Should repair work be required, parts needed to complete the repair will be ordered from the manufacturer and installed if the customer so desires. There is, however, a charge for this service.

The company will also provide immediate response to any hazardous situation that might cause threat to life or property after normal working hours (Mon – Fri, 5pm - 8am; Sat; Sun; & Holidays) at no charge, including:

- Fire or explosion
- Gas leak
- Damaged gas main or service (parts & labor may apply)
- Gas appliance that won't cut off
- Carbon monoxide investigation
- Leased water heater service within 24 hours

Services For Which There Are Charges

- Installation or connection of gas appliances
- Reconnects of gas appliances
- Repair of gas appliances where parts are needed (except central systems)
- Repair or replacement parts, electrical equipment, or thermostats on Arkla or Bryant gas air conditioners beyond Service/Warranty Contract
- Cleaning condensers and condensate lines on gas A/C units
- Gaslight repairs and reconditioning
- Miscellaneous pipe work
- Change outs and reconnects of food service equipment
- Repair of gas air conditioning units installed after January 1, 1975; units on which the Warranty/Service Contract has expired; and units or installations not approved by the Company's Service Department
- Work involving replacement of filters and out-of-warranty parts (charged on a "time and materials" basis)

- After hours work that requires a repair including commercial cooking and water heating equipment (the customer may be given the option for jobbing repair at the current overtime rate, if time and workload permits)

Work the Company Does Not Provide

- Replacement of filters in central heating equipment
- Installation, connection, or repair of unit heaters and central heating equipment
- Repair or replacement of unit heaters and other equipment requiring an electrician
- Repair or installation of gas appliances that are not AGA certified or where gas appliances are not used in accordance with manufacturer listing
- Repairs on heating equipment that requires parts will not be made except on those units sold by Nashville Gas prior to May 1, 1974. In addition, the Company does not install furnace filters
- No work will be performed on electrical air conditioning units installed with a gas furnace (this work will be referred to the installer or mechanical contractor)

Termination Policy

Reasons for Termination of Service or Denial of Service (1220-4-5-.18)

Service may be refused or discontinued for any of the reasons listed below. Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued.

1. With notice in the event of a condition determined by the utility to be hazardous
2. Without notice in the event of customer use of equipment or the utility's service to others
3. Without notice in the event of tampering with the equipment furnished and owned by the utility
4. Without notice in the event of unauthorized use
5. For violation of and/or non-compliance with the utility's rules on file with and approved by the Tennessee Regulatory Authority
6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Tennessee Regulatory Authority
7. For failure of the customer to permit the utility reasonable access to its equipment
8. For non-payment of bill provided that the utility has made a reasonable attempt to effectively collect and has given the customer written notice that he has at least five (5) days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied

9. For failure of the customer to provide the utility with a deposit as authorized by 1220-4-5-.14 of the Tennessee Regulatory Authority Statutes
10. For failure of the customer to furnish such services, equipment, permits, certificates, and/or rights-of-way, as shall have been specified by the utility as a condition to obtaining service, or in the event such equipment or permission are withdrawn or terminated.

Insufficient Reasons for Denying Service (1220-4-5-.19)

The following shall not constitute sufficient cause for refusal of service to a present or prospective customer:

1. Delinquency in payment for service by a previous occupant of the premises to be served
2. Failure to pay for merchandise purchased from the utility
3. Failure to pay for a different type of class of public utility service
4. Failure to pay the bill of another customer as guarantor thereof
5. Failure to pay a back bill rendered in accordance 1220-4-5-.17(a) of Tennessee Regulatory Authority Statutes.

Disconnection

The Company has the right to shut off gas from any consumer who may be in arrears for a longer period than twenty (20) days in paying for gas furnished hereunder or under any other prior or subsequent agreement, or for gas used by the consumer at the consumer's present or any prior subsequent address. The said twenty-day period commences to run from the date the bill was rendered. The Company will not shut off gas for non-payment without first mailing a notice to the consumer giving him seven (7) calendar days to pay the bill in arrears.

Reinstating Service

If natural gas service is disconnected for nonpayment, service will be restored after the customer has paid the total amount past due, paid the reconnection charge and paid a deposit.

Third-Party Notification

At the customer's request, the Company will send a copy of any disconnection notice to a designated third party. However, the designated third party is not responsible for paying the bill.

Medical Emergencies and Life Support Devices

The Company will delay disconnection of gas service for 30 days if a physician, public health officer or social service official certifies in writing that discontinuing gas service will worsen an existing medical emergency for a permanent resident of the premises where services are rendered. A prompt request is important. During the 30-day extension, payment of the bill must be guaranteed by another person or entity that is acceptable to the Company.

The Company will not disconnect service at the service address if there are natural gas appliances that are critical to maintaining the health of one or more permanent residents. The Customer Service Department must be contacted to determine whether a gas appliance is considered a life-support device.

Notice of Rights and Remedies

Should the Customer request help in paying his natural gas bill the Company will provide the customer with a list of community agencies that provide aid in paying their natural gas bill. The company will also, in some cases, make alternative pay arrangements if the customer is temporarily unable to pay his natural gas bill. However, if such an agreement is made the customer gives up their right to dispute the amount due under the agreement. If the customer does not fulfill the terms of the agreement, the Company may disconnect service and a new pay agreement will not be offered before we disconnect service.

If the Customer wants to appeal an unfavorable decision regarding a natural gas bill, they may contact the Tennessee Regulatory Authority's Complaint Division, 460 James Robertson Parkway, Nashville, TN 37219 (615-741-3939 or 800-342-8359). This must be done before the net due date if the dispute involves a disconnection notice. The Company will not disconnect service for nonpayment of the disputed portion of the bill while it is being reviewed. The Customers right to appeal will not expire if delay on the Company's part makes it impossible to contact the TRA within the required time period. The Customer also has the right to suspend payment of the disputed portion of the bill while the dispute procedures mentioned above are in progress.

Customer Classifications

Residential

Residential service applies to single private residences, including separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered. A dwelling shall be considered non-residential which has more than one apartment or condo on the same meter. A duplex, for example, shall be considered residential only if each of the two units is separately metered. A residential dwelling will also be considered commercial if in

the Company's judgment such dwelling and/or usage is identifiable as being used primarily (more than 50%) for business or professional purposes.

Commercial

Commercial service applies to customers engaged in selling, warehousing, or distributing a commodity or service in some business activity or profession or in some other form of economic or social activity. For example, and not by way of limitation, all local, state and federal governmental agencies, any organizations or institutions whether profit or non-profit, with uses other than those involving industrial or residential requirements are classified as commercial customers. Also included are offices, stores, schools, dormitories, hotels, restaurants, apartment houses, religious institutions, orphanages, clubs, boarding and rooming houses, communes, motor courts, camps, and rehabilitation organizations.

Industrial

Industrial service applies to customers primarily engaged in a process that creates or changes raw or unfinished materials into another form of product, including the generation of electric power.

Firm Service

Firm service applies to those schedules or contracts under which the Seller is expressly obligated to deliver specific volumes within a given time period and under which the Seller anticipates no interruptions. This obligation does permit unexpected interruption in those cases where the supply to higher priority customers is threatened.

Interruptible Service

Interruptible (Limited Availability) service refers to those schedules or contracts under which the Seller is not expressly obligated to deliver specific volumes within a given time period. This category of service anticipates and permits interruption on short notice, or service under schedules or contracts that expressly or implicitly require installation of alternate fuel capability.

Priority of Service

The Company has established the following categories of service in order of priority:

1. Residential, small commercial (less than 50 MCF on a peak day), school, hospital, police protection, fire protection, sanitation, or correctional facility requirements
2. Essential agricultural requirements

3. Large commercial requirements (50 MCF or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs, pipeline customer storage injection requirements, and firm industrial sales up to 300 MCF per day
4. All industrial requirements not specified in 2, 3, 5, 6, 7, 8, 9 or 10
5. Firm industrial requirements for boiler fuel use at less than 3,000 MCF per day, but more than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements
6. Firm industrial requirements for large volume (3,000 MCF or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements
7. Limited Availability requirements of less than 300 MCF per day, where alternate fuel capabilities can meet such requirements
8. Limited Availability requirements of more than 300 MCF per day but less than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements
9. Limited Availability requirements of intermediate volumes (from 1,500 MCF per day through 3,000 MCF per day), where alternate fuel capabilities can meet such requirements
10. Limited Availability requirements of more than 3,000 MCF per day, but less than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements
11. Limited Availability requirements of more than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements.

Meter Turn On

There is no charge for meter turn on for a new customer. There will be a flat charge for meter turn on for an existing customer or member of same family or household. For turning on meters shut off for non-payment of bills there will be a flat charge for meter turn on plus payment of all past due bills. The Company may also secure an additional customer deposit. If an existing customer requests that his/her meter be turned off for the summer to avoid minimum bills during the summer period and then requests the Company to turn the meter back on, the flat charge for meter turn on will apply.

Gas Wastage (1220-4-5-.06(iv))

Excessive gas consumption without knowledge by the customer may possibly be the result of gas leakage or appliance malfunction. Gas bill adjustments generally will not be permitted for improper and/or inefficient operation of gas appliances or for gas leaks. Adjustments for all special cases will be based upon individual merit dependent upon such factors as prompt action by the customer, the nature of the problem, maintenance of facilities by the customer, the time period involved, etc. An example might possibly be a

hot water relief valve stuck open or a broken hot water line on a gas water heater. All such special adjustments shall not exceed 35% of the wastage and shall be approved by the Director of Customer Service (residential) or the General Manager of Marketing (commercial). Wastage shall be based on Service Department inspection or Customer Service Department researches. The Director of Customer Service shall determine consumption rates. Duration of the adjustment shall not exceed 30 days. Where such gas appliance malfunction or gas leakage was directly caused by actions of Company personnel or occurred within 30 days of the date the work was performed by Company personnel, the Company will grant 100% credit of wastage to the customer. The amount of wastage will be approved by the Service Superintendent and not exceed a period of 30 days.

Title to Facilities

The title to all facilities including mains, gas service lines, meters, and accessory equipment up to and including the outlet of the meter assembly shall be vested in the Company, notwithstanding any charge which may be made to the customer for extending service.

Appliance Classifications

Major appliances

- central heating systems
- circulating heater*
- floor furnaces
- gas air conditioners
- water heaters

* A circulating heater will be considered as a major appliance when it has all of the following features:

1. Has an input rating of 40,000 BTU per hour or greater (two or more smaller vented circulating heaters having a combined output of 40,000 BTU or more will be considered as one major appliance)
2. Is used for heating throughout the heating season
3. Is the major source of space heating in the building

Minor appliances

- clothes dryers
- gas fireplaces
- gaslights
- grills

- incinerators
- log starters
- logs
- ranges
- swimming pool gas water heaters

General Installation / Connection & Repair Policy

The following regulations are applicable for residential natural gas appliance connections on Nashville Gas lines. The delivery and uncrating of the appliance is the responsibility of the customer/dealer. The connection/installation of commercial and/or industrial gas appliances is the responsibility of dealer. All natural gas appliance installations on Nashville Gas lines shall comply with the provisions of the Southern Gas Code (SBCCI), as updated. All appliances must also be AGA approved. The Company reserves the right to refuse to connect those appliances which, in its judgment, do not conform to appropriate safety requirements.

Space Heaters and Central Heating

The Company will provide free of charge: a service call to diagnose the problem, gas and air adjustments on burners and pilot assemblies, adjustments to controls and thermostats, and minor electrical repairs not requiring material. The Company shall not make repairs to gas furnaces other than pilots, thermocouples, or other parts we normally stock. A heating contractor, preferably the one who installed the equipment, will perform such repairs. The Company does not install air filters. The Company will make repairs to gas heating equipment that was installed by the Company. Such repairs will be charged to the customer on a "Time and Material" basis or at a flat charge if so provided for herein.

A **Gas Furnace Safety Inspection** is provided without charge by the Company and covers the following:

1. Check for gas leaks at the meter and on the customers' gas fuel lines.
2. Check furnace vent.
3. Safety inspection of the gas fired equipment to ascertain that safety and other limit controls are operating correctly.
4. Safety inspection of the furnace combustion chamber to determine if cracked or unsafe.

A **Gas Furnace Operational Inspection** is provided at the request of the Federal Housing Authority, Veteran's Administration, HUD, real estate/mortgage firms, or other parties interested in a more thorough operational inspection of the gas fired heating equipment. Such requests should be initially referred to the Marketing Department. There is a charge for this inspection that includes the following:

1. Check for gas leaks at the meter and on the customers' gas fuel lines.
2. Check furnace vent.
3. Safety inspection of the gas fired equipment to ascertain that safety inspection and other limit controls are operating correctly.
4. Inspection of the combustion chamber for safety (check for cracked chamber) and for operational purposes to determine the condition of furnace.
5. Calculate actual equipment input rate (Btu/h) to determine if the burner is operating in accordance with the manufacturers' instructions and rating plate.
6. Make an inspection of the air delivery system to check for the condition of ductwork and delivery of reasonable air volumes.
7. Provide a written report to the client on findings of Operational Inspection.

Automatic Vent Dampers

Automatic vent dampers that are AGA certified and UL listed are acceptable. Dampers must be installed in accordance with the manufacturer's instructions. The name of the qualified installing agency must be affixed to the damper. The vent damper must be so installed and wired so that upon failure it will "fail safe" in the open position. If not, the damper and the associated gas appliance will be red-tagged and turned off. The Company will not install, repair, or provide service on the damper installation. In the instance of a malfunction or a retrofit damper installation, the Company will secure the damper in a "make safe" position and advise the customer to secure repair through the distributor, manufacturer, or installing dealer. The Company does not endorse any specific brand unit and does not endorse or guarantee any claimed energy savings.

Unvented Gas Heaters

The use of UL listed unvented natural gas space heaters is permitted in accordance with the Southern Gas Association Code. However, they may not be located in bedroom areas or sleeping quarters, nor in confined areas where the listed total input rating of such heaters is greater than 30 BTU/HR/CF of space volume (confined space definition). Further, the gas meter will not be turned on in the following cases:

- Where unvented heaters are the primary source of heat in a residence
- Where unvented heaters are the primary source of heat in commercial or industrial structures unless specifically approved by the Service Superintendent or General Superintendent as being unconfined space and adequately ventilated

Gas Air Conditioning

On Arkla, Bryant, and other gas-fired air conditioning units connected to our lines, the Company will provide the following services without charge to the customer:

1. Make service call to diagnose the problem.
2. Perform gas and air adjustments to all burners and pilot assemblies.
3. Check thermostats and controls.
4. Pumping of water-cooled units in order to maintain operations.
5. Purging of non-condensables from air-cooled units.

Other than that described above, and unless specifically covered under appropriate customer Warranty/Service Contract, service work involving repair or parts replacement will be charged to the customer on a "Time and Material" basis. The General Manager of Marketing or the Service Superintendent will determine any exceptions. On request by customer, the Company will replace air filters on gas air conditioning system on our lines for a flat charge, regardless of the number of filters required per job. This will apply to plain flat filters only, not bag or other types.

Water Heaters

All installations of and repairs on water heaters purchased from Nashville Gas will be charged on a "Time & Material" basis. The Company will provide dip tube replacement, thermostat control, and other repairs to the residential customer for a charge based on "Time & Material". For repairs of commercial gas water heaters, the customer is to be referred to local dealer or plumber.

Dryers

Installations of and repairs on residential gas clothes dryers will be charged on a "Time & Material" basis. Repair requests on commercial gas clothes dryers, other thermocouples or other parts normally stocked by our storeroom, will be referred to the appropriate dealer for servicing.

Gas Grills

The Company, as part of its free service program, will make burner air and gas adjustments, check controls, and assist in problem diagnosis on a no-charge basis. Installations of and repairs on gas grills will be charged on a "Time & Material" basis. Cleaning and painting of the grill will be the responsibility of customer. The Company may also perform the following:

1. Post Replacement: Gas grill posts will be replaced for "Time and Material." If a special post must be fabricated, the cost of the installation and post will be "Time and Material."
2. Repairs to Cut or Damaged Tubing: If repair to tubing is performed by the Company, the charge will be "Time and Material". A service representative can sometimes perform this work, but generally a three-man fitting crew is required.
3. All Other Repairs -- All other repairs will be performed at "Time and Material".

Gaslights

With regard to gaslights, the Company will turn on, re-light and replace mantles without charge to the residential customer. Should the residential customer wish to replace the mantles himself, the Company will, upon request, mail to him replacement mantles for residential use in his gaslights without charge. Residential customers may also pick up free replacement mantles for use only in their gaslights at the Company's storeroom. The same gaslight service policies apply to commercial/industrial customers except they will be charged for the mantles. Subdivision entrances and multi-family developments do not qualify for residential use. Services do not include the painting of gaslights or glass cleaning; these are considered the owner's responsibilities.
The Company will recondition the customer's gaslight, including replacement of mantles, cleaning and/or replacement of glass panes as required, and painting repair of gaslight as necessary, for a flat labor charge plus cost of replacement parts (other than mantles). In the case of multiple gaslights on the same piece of property, the labor charge shall apply only to the first light. For each additional light on the same property, an additional charge plus parts (other than mantles) will apply. The same policy applies to commercial customers except they will also be charged for mantles. Installation of and repairs on gaslights will be charged on a "Time & Materials" basis. The Company may also perform the following:

1. Post and/or Light Head Replacement: Post only replacement will be performed by the company on a "Time & Material" basis. All customers needing to purchase a gaslight head will be referred to the Home Energy Center.
2. Repairs to Cut or Damaged Tubing: If repair to tubing is performed by the Company, the charge will be "Time & Material". A service representative can sometimes perform this work, but generally a three-man fitting crew is required.
3. Complete Replacement: The customer shall be referred to the Company's Home Energy Center. If the customer provides a replacement light head and post of the same basic type, the Company will connect the replacement, charging the customer on a "Time & Material" basis.

4. All Other Repairs: Other repairs will be performed on a "Time & Material" basis.

Gas Logs & Log Starters

All installations of or repairs on gas logs and log starters will be charged on a "Time & Material" basis.

Other Miscellaneous Residential Gas Appliances

All installations of or repairs on other approved gas appliances will be charged on a "Time & Material" basis.

Customer Options

In those instances where a flat charge for connection/repair is listed, the customer may elect prior to our performing the work involved to be charged on a "Time & Material" basis rather than the flat charge. However, having elected to take the T&M option, after the work is completed that decision cannot be reversed and customer will be charged on the "Time & Material" basis. All customer charges described herein are subject to change by the Company.

Appliance Parts Broken by Company Personnel

From time to time when our service personnel are repairing a customer's gas appliance, other adjacent parts become broken during the course of the repair. Such instances leave a question as to whether the customer should be charged for that additional part. Such decisions shall be at the discretion of the supervisor involved. The following guidelines should be of assistance.

No Charge to Customer

1. Breakage caused by negligence on part of our personnel. In such cases, the employee will be counseled to avoid repetition.
2. Accidental breakage of part considered "relatively new" and our representative was using care and attention to work procedures.

Charge to Customer

1. Parts that may be broken after customer first being warned that we will use care in repair but the customer will be responsible for all parts involved. If the service representative has doubts about the condition of the appliance, he should so warn the customer initially.
2. Any parts broken which are not "relatively new" and in process of normal repair with our representative using reasonable care in work procedures. Where we

make a mistake we'll stand behind it, but we will not unilaterally absorb the cost of other parts broken, they will be considered part of the job.

Sales to Employees

The following is applicable for active permanent employees, retired employees and retiree's surviving wife or husband until such time as survivor remarries:

1. Employees may purchase Natural Gas Appliances and accessories at cost from the Home Energy Center. Appliances must be purchased for use only in the employee's own home.
2. Pipe, pipe fittings and similar material carried in stock by the Company may be purchased by employees at warehouse cost, but these also must be used in the employee's own home. The employee's department head must approve purchases exceeding $15.00. Each month, a list of employee purchases will be supplied to the employee's department head. Each purchase must be released to personnel for documentation and approved by the Customer Service Department if financing is requested.
3. Central gas HVAC systems purchased through Qualified Gas contractors and financed through the Nashville Gas Financing Program will be financed at the lowest rate available to customers. (Presently 8.9%) The units must be installed in the employee's own home.

There is no intent in these rules for employees to unfairly benefit from Company discounts. The giving of false information to obtain a discount from the Company will be considered a cause for discipline.

When an employee purchases a qualifying residential natural gas appliance from the Home Energy Center for connection on Company gas lines for use in his own home, the Company will provide normal installation at cost with no mark up to the employee. Qualifying residential natural gas appliances are as follows:

- Gas Dryer
- Gas Range, Cooktop, or Walloven
- Gas Grill
- Gas Water Heater
- Gas Space Heaters
- Gas Logs or Log Starter
- Gaslight

Appliances purchased elsewhere will be installed at the normal installation charges as set forth in the service Rules and Regulations Manual. Floor furnaces, central heating and cooling equipment, including pre-vent heaters and wall furnaces, commercial appliances, and pool heater installations are also not qualifying and should be referred to plumbing or

mechanical contractors. Relocation of the above listed applicable natural gas appliances, within an employee's own home, will be performed at cost of labor and materials, but no overhead will be charged.

Residential appliance repair on natural gas appliances in use by employee in his own home on Company lines will be performed by the Company with the employee being charged only for the cost of materials with no overhead. Replacement of furnace combustion chambers is not included in this program. Warranty repair work for an appliance obtained from a dealer and still in warranty will be performed by the dealer. The Vice President of Tennessee Operations and the Superintendent of the Service Department will resolve any questions or interpretations of the above policies.

Liquid Propane Conversion to Natural Gas

Any new conversion customer converting from liquid propane (LP) to natural gas will receive gas service line and meter installation on the same basis as any other residential or commercial customer. The fuel lines and any other required conversion labor and materials from the meter to the gas equipment will be the responsibility of the customer. Contractors other than Nashville Gas must perform these conversions.

Residential
Conversion of AGA approved residential gas dryers, grills, logs, and ranges from LP to natural gas is available for a flat charge for each appliance. This charge is to include change of burner orifices and addition or modification of gas appliance pressure regulator. Where a burner cannot be converted and new burner is required, the conversion charge will be "Time and Material." The charge for conversion of more than one of these appliances at the same time, shall be "Time and Material". Conversion of furnaces or other appliances will be done on "Time and Material" basis.

Commercial
Conversion of AGA approved residential gas appliances or commercial gas appliances in a commercial structure will be performed on a "Time and Material" basis. Service line and meter installation will be on the same basis as any other new customer. Any necessary fuel line, house piping and appliance connection will be done on a "Time and Material" basis.

Temporary Conversions to Liquid Propane
When deemed necessary by Nashville Gas, new construction and conversion customers will be temporarily converted to liquid propane at no charge. The conversion back to natural gas will also be performed by Nashville Gas at no charge.

Nashville Gas Company Service Regulations

Section 2 – METERS

Installation & Location

The Company performs standard meter installation at no charge to the customer. However, a customer desiring an underground meter installation will be charged for the additional cost. The most desirable and serviceable location for a new residential meter installation is on the outside of the structure, approximately four feet past the front wall, where it is not subject to damage from automobiles. The new meter shall be so located unless it is physically impractical or it interferes with customer's use of his property. If a problem arises, the Service Superintendent and General Manager of Marketing will make a decision on a location after consulting with the Construction Superintendent. Underground meter locations will not be used except as approved by the Vice President of Tennessee Operations.

The proper meter location for large outside commercial or industrial meters, especially those having multiple structures, is at the property line wherever possible. Under no circumstances shall a meter be located within 10 feet of a combustion air intake. Further, meters shall not be located within 3 feet of an ignition source such as heating or air conditioning equipment, water heaters, electric meters, switch gear, electric panels, etc.

The customer or owner must at all times provide a proper and accessible location for all meters and regulators. The following rules apply as well:

1. All meters installed on high-pressure services must be installed outdoors.
2. All "farm tap" meters shall be located at the main.
3. All meters served from standard and medium pressure mains shall be installed outdoors, except in those instances in which it is extremely difficult to do so or is very undesirable from the customer's viewpoint. In such cases, the meter may be installed indoors, at the discretion of the Company, if the installation conforms to applicable codes.
4. If a customer desires to use gas solely for swimming pool water heating, the meter shall be located at the house and the fuel line run from this point to the pool heater.
5. If located indoors, the meter shall not be located:
   a. Above the ground floor
   b. Less than 3 feet from a hot air furnace or boiler
   c. Less than 3 feet from a gas oven or hot water heater
   d. On or under stairways
   e. In bathrooms or adjoining clothes closets
   f. In small, unvented, or confined spaces

g. Where subject to damage, extreme high temperature, or corrosion
h. In entrances or exits so as to obstruct passage in any way
i. Less than 10 feet from boilers or other sources of heat, if the meter capacity is 80B or larger

Meter Relocation

Outside meters will be relocated when requested by the customer, however, the customer will be charged Time and Material.

Meter Testing

The Company maintains a regular program of meter testing and change-out to insure metering accuracy. Upon written request from the customer for a special test of his meter, the Company will inspect the meter at a reasonable time in accordance with provisions of Rules, Regulations and Statutes Governing Public Utilities as issued by the Tennessee Regulatory Authority. Such meters will be considered to register correctly if the error is not greater than plus or minus two percent (2%). If the meter is found to be registering incorrectly, the meter will be repaired or adjusted to conform to standards with no charge to the customer for testing or repair. If the meter is registering correctly, there will be a meter testing charge to the customer.

Meter Tampering or By-pass

The term "metered gas" is defined as "all gas that has passed through the customer's meter." It is Company policy to prosecute those persons involved where the Company finds evidence of meter tampering or by-pass. Such acts are illegal, as well as extremely dangerous, and Tennessee State Law provides for substantial punishment. In such cases, the customer or party involved will be charged for all gas used and the cost of meter repair including travel time and all other related expenses on a "Time and Materials" basis. At the Company's option, gas service may also be terminated. The Regional Customer Service Manager, the Manager of Meter Reading, and the Service Superintendent will handle such investigations.

Meter Damage

The customer has a responsibility to provide reasonable protection for the Company's metering facilities from damage by his employees, customers, and the general public. It is not, however, his equipment and he cannot be expected to provide security such as guards, surveillance, enclosures, etc. to protect the Company's meters from acts of vandalism or from the general public. The Company selects and approves meter locations.

If a location is in a drive, parking lot, alley, etc. where damage is likely, then it is the Company's responsibility to provide adequate protection such as posts, etc. In cases where the Company's metering facilities are damaged, the Service Department shall conduct investigations of the incidents. The Chief Engineer will approve all proposed meter damage bills after consultation with the General Manager of Marketing and the Service Superintendent. With regard to actual damage responsibility, the following applies:

1. If the customer or his employees cause damage (accidentally or purposely), then the customer should be billed for damages.
2. If a visitor, commercial vehicle, or general public vehicle damages a meter, damage relief should come from that person or firm causing the damage. Damage relief shall not come from the customer, unless it can be proven that the damage by a third party resulted from negligence on the customer's part.

Nashville Gas Company Service Regulations

Section 3 – FUEL LINES

Customer gas fuel lines installed on Company mains shall comply with provisions of the Southern Gas Code (SBCCI), the appropriate gas code recognized by the Metropolitan Government of Nashville and Davidson County, Nashville Gas, or other county regulations. The care and maintenance of all customer-owned underground fuel lines is the responsibility of the customer. All piping carrying metered gas is considered a fuel line. When in place in a finished building, hidden from view and not easily accessible, the piping is considered a concealed fuel line. All fuel lines will be (a) standard threaded and coupled or welded steel minimum schedule 40 pipe (depending on operating pressure), or (b) plastic pipe or tubing of the following types: TR-418 PE 2306 -- orange color, Drisco 7000 or 8000 PE 3406 -- black color, or approved equal.

Fuel Lines May

- Be installed underground in accordance with applicable codes to include corrosion protection.
- Be installed to serve any number of buildings if all the buildings are located on a single or continuous tract of land with common ownership.
- Be concealed if installed in accordance with applicable codes.

Fuel Lines May Not

- Be smaller than 1-1/4" coated steel or 1-1/8" x.090 wt Polyethylene (PE) tubing if installed underground (unless serving only gaslights, grills, or logs). Fuel lines to remote heating units may be smaller as approved by the Service Department. The Service Department will determine the size of fuel lines for mobile homes.
- Extend to or across property under different ownership.
- Cross any public street, alley, or highway. Fuel lines shall be sized to have a minimum pressure drop between the meter outlet and any appliance of 0.3-inch water column. Those fuel lines served from standard pressure distribution systems will be sized on 0.2-inch water column pressure drop.

Installation Charges

All fuel lines will be installed at the customer's expense with one exception: when determined necessary, the Company may choose to install a fuel line instead of a service line. In this event, ownership with maintenance responsibility shall remain with the customer. In such cases, footage of fuel line installed shall be equal to the footage of

service line that would be "free service" if the customer were served in the usual manner (a "farm tap" customer is an example). Charges for residential underground fuel lines will be "Time & Material." Pre-installation estimates may be obtained from the Service Department (for plastic tubing) or the Construction Department (for all other underground fuel lines). The customer at his expense will replace any sidewalk or pavement cut. The customer will be charged "Time and Materials" for all fuel line repairs (excluding tubing to gaslights and grills) made by the Company.

Commercial or Industrial Fuel Lines

Commercial or Industrial fuel line piping work requests shall be referred to local plumbing contractors, except in special cases as approved by the Superintendent of Construction and the General Manager of Marketing. If the Company installs a customer's underground fuel line, the charge will be "Time and Materials."

Nashville Gas Company Service Regulations

Section 4 – SERVICE LINES

Service lines are pipes used to carry unmetered gas from the main to the customer's meter. The preferred route of the service line will be from the nearest adequate main to four (4) feet beyond the customer's nearest building wall. Service lines, service relocations, and extensions may be installed in accordance with applicable codes by either the Company or by a contractor approved by the Company. The complete installation must be inspected and approved, prior to being backfilled, by the appropriate Company representative. In general, service lines should not be laid on vacant property adjoining the building to be served if there is likelihood that a building will be constructed on the vacant property. Service line installation policies are subject to conditions of gas supply and the Company's limited service attachment programs.

Customer Types

Residential

The Company will install free of charge 100 feet of service line for one major appliance where no main extension is required. An additional 50 feet of service line shall be installed free of charge for each additional appliance. These footages refer to the service line between the customer's property line and four (4) feet past the nearest outside building wall. The customer shall replace any sidewalk or pavement on his property that is cut.

For service lines to supply appliances not included as major appliances, the customer shall be charged the Company's actual cost for the entire length of the service line from the main to the meter. However, this rule shall not be construed as prohibiting the Company from installing service lines for certain groups of minor appliances as long as the installation is made under more favorable terms to the customer and no discrimination is practiced between customers whose service requirements are similar.

Commercial or Industrial

For permanent use and where revenues justify, the Company will install free of charge 100 feet of service line measured from customer's property line or four feet past the nearest building wall, whichever is less.

Charges

The facilities to be installed by the Company as described above will be at no cost to the customer if (1) at a minimum the customer will be installing central gas heating or gas water heating, (2) the gas service line extends along the route selected by the Company and (3) the length of the gas service line is no greater than allowed, as shown above. In the event that the above conditions are not met, the service line installed for the customer must provide a reasonable return to the Company, If the customer wishes the facilities to be constructed along a route other than the route selected by the Company and/or if the gas service line is more than the length allowed above and/or the service to be rendered to the customer will not produce a reasonable return to the Company, the Company may require the customer to pay the excess cost of constructing the facilities along the alternate route or in excess of the footage allowed and/or to make a contribution which will permit the Company to earn a reasonable return. In all cases any pavement or sidewalk cut will be replaced by and at the customer's expense.

Exceptions

In cases where there is exceptional cost due to length of service, paving (such as crossing major street), rock, etc., these service orders shall be reviewed by the Engineering Department on a case-by-case basis to determine if they meet the main extension policy provided in Section 5. The Chief Engineer and the General Manager of Marketing must approve these exceptions.

Excess Service

Excess service refers to that portion of the total cost of a service line installed for a customer that is in excess of the Company's justifiable investment and is that portion of service line cost paid for by the customer. A customer may pay the excess service charge with cash or credit with approval, and may spread the cost over three years on a monthly installment payment basis.

Repairs

Repairs to service lines damaged by others shall be charged at the Company's actual repair costs.

Service Extensions

A service extension includes all piping carrying unmetered gas from the termination of the previous service line to the inlet of the meter. Service extensions and relocations shall be installed at the customer's expense.

Branch Services

Branch services will be permitted only when the point of junction of the two services is either in the public right-of-way or on a customer's property. In the latter case, written and notarized permission of the property owner must be obtained and filed with the Register of Deeds of the appropriate county. In the case of services requiring in-line valves, the service must be branched in the public right-of-way, and the Construction Department must confirm presence of a valve in each branch.

Multiple Buildings on Same Lot

In those cases where two or more buildings are located on the same lot in such a manner as to be reasonably suited to subdividing, the Company will, if requested, run separate service lines to these buildings. However, if the buildings are not so situated (e.g. garage apartments or combination commercial and residential buildings), the Company will not run separate services except where the full cost of the additional service from main to meter, including paving, is borne by the customer.

Service Line Enlargements

If the load through an existing service is so increased as to require a larger service line, the Company will enlarge the existing service to a point four (4) feet beyond the customer's nearest outside building wall without charge. Any enlargement of the service line beyond this point will be at the customer's expense. Any fuel line changes will be at the customer's expense.

Shopping Centers

A shopping center shall be considered as a single structure containing a minimum of 7,500 square feet of floor space and a minimum of four (4) tenants or business stores operating within the structure. The Company shall install one service line and one bank of gas meters for each 12,000 square feet of floor space. The final number of meter banks shall be at the discretion of the General Manager of Marketing, based upon the size and layout of the particular shopping center under consideration.

Nashville Gas Company Service Regulations

Section 5 – MAINS

The Company has a policy of extending its main(s) to serve a new customer (or customers) provided such main extension is determined to be economically feasible. The criteria for economic feasibility shall be met when the total annual net revenue to be obtained from the customer (or customers) provides a rate of return that is equal to or greater than the overall cost of capital established in the Company's last general rate case.

The determination of the anticipated rate of return on the main extension will be based on a net present value (NPV) computation utilizing the following parameters:

1. Net revenues will be calculated by applying the applicable tariff margin rate to the estimated annual total usage and, where applicable, potential for future growth may be considered.
2. Estimated annual total usage shall be based on those appliances that will be in use during the first five (5) years of service, except as provided in paragraph 3 under "Main Extension Contract".
3. The required investment will be based upon engineering cost estimates as determined by the Company and will include the costs of all facilities required for providing service including material and labor costs associated with the installation of mains, service lines, metering and regulating equipment, easements, rights of way, street crossings, and all other required equipment or facilities.
4. The discount rate shall be equal to the overall cost of capital allowed in the Company's last general rate case adjusted for taxes and depreciation.
5. The discount period shall be equal to the economic useful life of the investment in the mains and services.
6. Main extensions producing a positive net present value at the end of the discount period shall be considered economically feasible.

Main Extension Contract

To the extent the net present value computation produces a negative result:

1. The customer shall pay to the Company an amount equal to the negative net present value at the end of the discount period, plus any additional funds required to provide for the payment of resulting taxes. This payment may be made in a lump sum or in periodic payments (without interest) -- annual, monthly, etc.
2. If within three (3) years after the original installation, the customer making the payment adds additional major or minor appliances, the Company will refund to the customer (if

paid in advance or credit his account if on extended terms), upon written request, an amount equal to the net annual revenues anticipated to be realized from the usage of the additional appliance(s).

3. If within three years after the original installation additional customers are connected to the main then the Company shall refund (or credit his account) to customers making the payment, upon written request, an amount equal to the net annual revenues anticipated to be realized from the additional customer(s).
4. In no case shall the customer making the payment be refunded more than he paid.

The above provisions assume that only one customer will make the payments. If two or more customers make the payments, the contract will be adjusted to reflect this fact; for example, if two customers made equal payments and a refund is due because one of the two has added an additional appliance, then the entire refund shall be paid to him.

Exceptions

The Company may make exceptions to the main extension rule when system improvements are realized by the extension.

Main Relocation

If a customer requests a re-routing or relocation of a main located on a public right-of-way, the customer will be charged for this work. If the main is located on private property, such as an easement, railroad right-of-way, the case will be referred to the Engineering Department for determination as to whether a charge shall be made. The same will apply to relocations or re-routings requested by a contractor. Repairs to mains damaged by a contractor will be charged to the contractor on a "Time and Materials" basis.

Aboveground Facilities

If the above-ground facilities (such as post regulators, vent pipe, etc.) are so located that they seriously interfere with, or make impracticable, the owner's use of this property, the relocation of such facility will be done at no cost to the customer. An example of serious interference would be when the aboveground facility was located in front of a proposed narrow driveway. In all other cases, the cost of relocation will be charged to the customer. In those cases where it is difficult to determine whether the customer is to be charged for the relocation, the decision shall be made by the Vice President of Tennessee Operations. The charge, unless specified for any of the above items, will be either of the following, at the customer's option, prior to commencement of work:

1. Estimated cost as determined by the Construction Department
2. Actual cost

Nashville Gas Company Service Regulations

Section 6 - Rules and Regulations Governing Supply & Consumption of Gas

The consumer agrees to the following rules and regulations, having made proper application and deposit for service with Nashville Gas Company.

1. Consumer is responsible for damage to any gas meter or equipment belonging to the Company placed on the premises occupied by the consumer and will immediately reimburse the Company for all costs of repairing or replacing same. In accordance with Item (1), Section 1220-4-5-. 18, Reasons for Denial of Service of the Tennessee Regulatory Authority's Rules and Regulations, a consumer may be refused service if consumer has damaged the Company's equipment or tampered with the lock on a meter. The Company will charge $45.00 for a broken meter lock.
2. Consumer will use gas supplied through Company's meter only. Use of other metering devices or bypassing equipment and tampering or adjustments on company-owned metering facilities by consumer are prohibited. The Company will not permit secondary meter billing.
3. In case the meter has failed to register the quantity of gas consumed, in whole or in part, the consumer will pay such reasonable sum as is ascertained to be due for the period involved.
4. The Company's authorized agents shall have access to consumer's premises at all reasonable times for the purpose of checking, reading, servicing, and disconnecting the meter; shutting off gas; and for such other purposes as the Company may deem advisable to protect its interests.
5. The Company shall be under no duty to inspect, repair, or maintain the service of other pipes, connections, equipment, or appliances located beyond the meter outlet on the premises of the consumer.
6. The consumer shall be liable and shall pay for all gas passing through the meter until it is turned off. When termination of service is requested, consumer must ensure that the Company receives either written or verbal notice at least two days prior to the desired date of termination. Access to the meter must be provided.
7. The consumer is entitled to the usual discount allowed by the Company if bills are paid within the first twelve days following the date bills are rendered. All gas bills are due when rendered and they will be considered as rendered when mailed to the address specified by the consumer. A residential, head of household consumer dependent on social security or other retirement check may request a net to gross

discount waiver. Qualified consumers will be granted a net to gross discount waiver and the account will be monitored for continuing compliance.

8. The Company shall have the right to shut off gas from any consumer who may be in arrears for a longer period than twenty days in paying for gas furnished hereunder or under any other prior or subsequent agreement, or for gas used by consumer at consumer's present or any prior or subsequent address, it being understood hereby that said twenty day period commences to run from date the bill is rendered as above defined. The Company will not shut off gas for non-payment without first mailing a notice to the consumer giving him seven days to pay for the bill in arrears.
9. The Company is authorized to require the consumer to make a deposit, or increase any existing deposit, in such amount as the Company deems proper for its protection before restoring gas service. The deposit amount will not exceed two consecutive billing periods or ninety (90) days, whichever is less.
10. If a consumer is found using gas service without having made proper application and deposit, a notice to the consumer will be delivered to the premises and the consumer will be allowed four days in which to make proper application before the service is discontinued.
11. All consumer deposits will accrue simple interest on the principal at the rate of six (6) percent per annum.
12. The Company will charge $50.00 for turning on a meter for an existing consumer or member of the same family or household at same address. This charge applies only to those consumers who have previously elected to have the meter turned off without discontinuing service or whose account has been closed because of non-payment of a bill.
13. In the event gas is shut off because of consumer's failure to pay, a charge will be made for each restoration. The Company will charge $50.00 plus payment of past due gas bills for turning on meters shut off for non-payment of bill. The Company will not be liable for damages for shutting off gas or for delay in restoring service. An additional deposit may also be required.
14. The consumer agrees to notify Company in advance of any planned change in physical premise or environment around meter or service to determine impact on safety cases, meter reading, and meter maintenance.
15. In the event the Company is unable, wholly or in part, by reason of force majeure to carry out its obligations to provide service, the obligations of the Company so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. The term "force majeure" as employed above shall mean acts of God; extreme weather conditions; strikes, lockouts, or other industrial disturbances; acts of the public enemy; war; blockades;

insurrections; riots; epidemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; arrests and restraints of governments and people; civil disturbances; explosions; breakage of or accidents to machinery, lines of pipe, or the Company's peak shaving plants; freezing of wells or lines of reduction in gas pressure by its suppliers; inability to obtain rights-of-way, permits, materials, equipment, or supplies for use in the Company's peak shaving plants; and any other causes whether of the kind herein enumerated or otherwise, not within control of the Company, and which by the exercise of due diligence the Company is unable to prevent or overcome. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Company, and the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts when such course is inadvisable in the discretion of the Company.

16. When the Company in its discretion determines that it is necessary to curtail service to maintain the integrity of its distribution system or to provide for its or the public's safety, the Company shall have the right to curtail delivery of gas to any consumer.

17. In the event of a failure or interruption of service, the Company shall use all reasonable diligence to remove the cause or causes thereof, but the Company shall not be liable for any loss or damage resulting from such failure or interruption due to accidents, force majeure, extreme weather conditions, or causes beyond its control.

Schedule VI

Nashville Gas Company
Results of Operations
For the 12 Months Ending May 31, 2001

Line No.			
1	Rate Base	$	235,725,376
2	Operating Income at Present Rates		19,502,031
3	Earned Rate of Return		8.27%
4	Fair Rate of Return		9.56%
5	Required Operating Income		22,535,346
6	Operating Income Deficiency		3,033,315
7	Gross Revenue Conversion Factor		1.629900
8	Revenue Deficiency	$	4,944,000

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

July 15, 2004

IN RE:	)	
	)	
APPLICATION OF NASHVILLE GAS	)	**DOCKET NO.**
COMPANY, A DIVISION OF PIEDMONT	)	**03-00313**
NATURAL GAS COMPANY, INC. FOR	)	
AN ADJUSTMENT OF ITS RATES AND	)	
CHARGES, THE APPROVAL OF REVISED	)	
TARIFFS AND THE APPROVAL OF	)	
REVISED SERVICE REGULATIONS	)	

ORDER APPROVING RATE INCREASE AND RATE DESIGN AND APPROVING RATES FILED BY NASHVILLE GAS COMPANY

This matter came before Director Pat Miller, Director Sara Kyle, and Director Ron Jones, of the Tennessee Regulatory Authority ("Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on September 22, 2003, for consideration of the *Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges, For Approval of Revised Tariffs and Approval of Revised Service Regulations* ("*Application*") filed on April 29, 2003. As more fully described herein, and for the reasons set forth below, the panel voted unanimously to grant the request of Nashville Gas Company ("NGC" or the "Company") to increase its rates. Additionally, a majority of the panel voted to approve a rate design implementing the increased rates.

BACKGROUND

NGC's *Application*

NGC filed its *Application* together with a proposed tariff for a rate increase on April 29, 2003. In the *Application*, NGC requested that it be allowed to earn an overall rate of return of ten and twenty-three one hundredths percent (10.23%) and a twelve and six-tenths percent (12.6%) return on equity during the attrition year ending October 31, 2004. The Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate" or the "CAPD") filed a petition to intervene on May 14, 2003. In support of its *Application*, NGC filed sworn testimony, together with exhibits, of the following witnesses: Thomas E. Skains, President and Chief Executive Officer of Piedmont Natural Gas Company; Chuck Fleenor, Vice President of Planning and Rates of Piedmont Natural Gas Company; Bill R. Morris, Director of Corporate Planning and Corporate Development of Piedmont Natural Gas Company; David Carpenter, Director of Rates of Piedmont Natural Gas Company; and Donald A. Murry, Economist with C. H. Guernsey & Company, Oklahoma City, Oklahoma.

NGC's *Application* was considered at a regularly scheduled Authority Conference held on June 2, 2003, at which time the panel voted unanimously to suspend NGC's proposed tariff, convene a contested case, grant the intervention of the Consumer Advocate, and appoint Director Pat Miller as the Hearing Officer in this proceeding for the purpose of preparing this matter for hearing. The Hearing Officer conducted a Status Conference on June 17, 2003 and thereafter, by way of an order issued on June 18, 2003, established a procedural schedule for discovery and the filing of testimony and set this matter for hearing on September 9 and 10, 2003.

On June 26, 2003 NGC filed a letter revising and amending the Service Regulations previously filed as part of their *Application*. On August 1, 2003 Associated Valley Industries, Inc. ("AVI") filed a petition to intervene. On August 7, 2003 NGC filed a request to modify the procedural schedule without modifying the hearing dates set by the Hearing Officer's June 18, 2003 order. On August 8, 2003 the Hearing Officer issued an order modifying the procedural schedule as requested and maintaining the September 9 and 10, 2003 hearing dates. A separate Notice of the September 9 and 10, 2003 hearing dates was also issued on August 8, 2003. On August 13, 2003 the Hearing Officer issued an order granting AVI's petition to intervene.[1] Thereafter NGC and the Consumer Advocate conducted discovery in the form of interrogatories and requests for production of documents pursuant to the Hearing Officer's procedural schedule.

A Status Conference was held on September 8, 2003. During the Status Conference, counsel for NGC and the Consumer Advocate confirmed that they had reached a tentative settlement of the case and were in the process of reducing the settlement to a written agreement. Thereafter counsel for the parties requested that the Hearing begin at 3:00 p.m. the next day rather than at 9:00 a.m. as originally scheduled. The Hearing Officer granted the parties' request and rescheduled the Hearing to begin at 3:00 p.m. on September 9, 2003.

The Hearing

This matter came before the panel of Directors for Hearing on September 9, 2003. Participating in the Hearing were the following parties and their respective attorneys:

[1] AVI was served copies of all filings in this docket but did not actively participate in this docket

Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. – R. Dale Grimes, Esq., Bass, Berry & Sims, PLC, AmSouth Center, Suite 2700, 315 Deaderick Street, Nashville, Tennessee 37238 and James H. Jeffries IV, Esq. and Jerry Amos, Esq., Nelson, Mullins, Riley & Scarborough, L.L.P., Bank of America Corporate Center, Suite 2400, 100 North Tryon Street, Charlotte, North Carolina 28202;

Consumer Advocate and Protection Division – Timothy C. Phillips, Esq. and Joe A. Shirley, Esq., Office of the Attorney General, P.O. Box 20207, Nashville, Tennessee 37202.

AVI did not participate in the Hearing.

During the Hearing counsel for the parties submitted the *Stipulation*, reflecting the settlement agreement of the parties, for the consideration of the panel. The *Stipulation* was also filed in the docket file on September 9, 2003. The *Stipulation* contained the following language:

> The parties to this settlement have engaged in substantial discovery and have undertaken extensive discussions to resolve all known disputed issues in this case. In addition, the Staff of the Authority has engaged in discovery. As a result of the information obtained during discovery and the discussions between the Company and the CAPD, the parties to this stipulation have agreed to adjustments to revenues, expenses, net operating income, net operating income for return, rate base and return on rate base. These adjustments reduce the Company's additional revenue requirements from $18,315,475 to $10,300,000. The Staff of the Tennessee Regulatory Authority has identified certain adjustments which the parties agree are included in the $10,300,000 settlement amount.
>
> The parties agree that the adjustments referred to [above] include the following: (a) reduction to correct meter reading errors in the test period; (b) increase to include uncollectibles expense; (c) reduction to correct accumulated depreciation; (d) increase to include gas odorant costs; (e) decrease to remove certain consulting fees; (f) increase to reflect additional coverage and cost of directors and officers liability insurance; (g) decrease to reduce pension expense to reflect updated pension contributions; (h) increase to recognize new rate for state excise taxes; (i) decrease to reflect lower carrying charges for gas inventory; (j) decrease to eliminate short-term incentive bonus; and (k) decrease to eliminate GTI funding. The elimination of GTI funding from expenses in this case is not intended to prevent the Company from making contributions to GTI.

The parties were unable to reach an agreement as to various capital structure, cost of capital and rate of return issues; however, the parties agree that the increase of $10,300,000 results in reasonable rates.

The parties to this settlement jointly recommend to the Authority that the Authority issue an order authorizing the Company: (a) to increase its rates to produce additional revenues of $10,300,000 effective November 1, 2003; (b) to implement the revised rates attached hereto as Schedule I effective November 1, 2003; (c) to use the fixed gas costs set forth on Schedule II attached hereto in future true-ups of gas costs under the Company's Purchase Gas Adjustment (PGA); (d) to use the "R" values, base load factors and heat factors set forth on Schedule III attached hereto in future rate adjustments under the Company's Weather Normalization Adjustment (WNA); (e) to implement the revised tariffs attached hereto as Schedule IV effective November 1, 2003; and (f) to implement, effective November 1, 2003, the revised Service Regulations filed with the Authority on April 29, 2003, as amended by letter filing of June 26, 2003.

The parties hereto agree that the revised rates and tariffs agreed to herein are fair and reasonable to all customer classes and will provide the Company with a reasonable opportunity to recover the agreed upon additional operating revenue requirement and a reasonable rate of return on investment. The parties further agree as follows: (a) the Company's rate base is $259,859,927; (b) the Company's existing rates will permit it to earn an operating income of $15,602,432; (c) to earn a reasonable return on its investment, the Company should be permitted to earn an operating income of $21,880,206; (d) unless changed, the Company's existing rates will cause the Company to have an operating income deficiency of $6,277,774; (e) the gross revenue conversion factor is 1.640709; (f) the revenue deficiency is $10,300,000 ($6,277,774 x 1.640709); and (g) the fair rate of return on investment is within the range of 8.0% to 9.0%.

At the outset of the Hearing, the attorneys for the parties each expressed their respective clients' support for the *Stipulation*. After hearing from the parties, the Directors voted unanimously to continue the Hearing until September 22, 2003 at which time the panel would deliberate the merits of the *Stipulation* following the regularly scheduled Authority Conference.

After the September 9, 2003 Hearing, and prior to the resumption of the Hearing on September 22, 2003, the Consumer Advocate and NGC filed responses to data requests regarding the *Stipulation* issued by the Authority.[2]

The panel reconvened on September 22, 2003 and deliberated the merits of the *Stipulation*. Thereafter the panel voted unanimously to approve the requested rate increase as modified by the *Stipulation*. A majority of the Directors voted to approve the rate design set forth in the *Stipulation*.[3]

Criteria For Establishing Just And Reasonable Rates

The Authority considers Applications for a rate increase, filed pursuant to Tenn. Code Ann. § 65-5-203, in light of the following criteria:

1. The investment or rate base upon which the utility should be permitted to earn a fair rate of return;

2. The proper level of revenues for the utility;

3. The proper level of expenses for the utility; and

4. The rate of return the utility should earn.

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[2] *See* Letter from William H Novak, Chief, Energy and Water Division to R Dale Grimes, Esq , Counsel for Piedmont Natural Gas Company, Mr Bill Morris, Director of Corporate Planning & Development; and Timothy Phillips, Esq , Assistant Attorney General, Office of the Attorney General, Consumer Advocate Division (September 11, 2003). Letter from Ron Jones, Director, Tennessee Regulatory Authority to R. Dale Grimes, Esq., Counsel for Piedmont Natural Gas Company; Mr Bill Morris, Director of Corporate Planning & Development, and Timothy Phillips, Esq., Assistant Attorney General, Office of the Attorney General, Consumer Advocate Division (September 12, 2003). *Response to TRA Data Request Dated September 11, 2003* (September 15, 2003). *Response to TRA Data Request Dated September 12, 2003* (September 16, 2003) Letter from James H Jeffries IV to Pat Miller, Director, Tennessee Regulatory Authority (September 16, 2003). Letter from James H Jeffries IV to Ron Jones, Director, Tennessee Regulatory Authority (September 16, 2003) (There are two letters from James H. Jeffries IV addressed to Director Ron Jones and filed on September 16, 2003 responding to separate data requests)

[3] Director Jones declined to vote with the majority with regard to the rate design portion of the *Stipulation* Director Jones could not find any basis in the *Stipulation* for dividing the residential class into two different classes that did not exist prior to the filing of the *Stipulation* or with one class bearing more of the demand reallocation than another and no part of the demand reallocation being placed on special contract customers *See* Transcript of Proceedings, p 71 (September 22, 2003)

Findings and Conclusions

After reviewing the record, including all exhibits, the TRA makes the following findings and conclusions.

Test Period

The objective of selecting a test period is to obtain financial data and adjust it as necessary to reflect the inter-relationship of revenues, expenses and investment expected to occur in the immediate future. In this case, the Company selected the twelve months ended December 31, 2002, as the historical test period and made two levels of adjustments. The first adjustment normalizes the test year and the second adjusts the normalized year to arrive at the forecast for the attrition year, which is the twelve months ending October 31, 2004. The *Stipulation* between the parties as to this issue is adopted. The TRA therefore finds that this attrition period will allow the Company the opportunity to earn a fair rate of return on its investment.

Rate Base

The parties stipulated as to a rate base for the attrition year in the amount of $259,859,927, as detailed below. The TRA finds that the rate base in this case has been adjusted to reflect the investment and expenses of the Company for the attrition year test period and therefore is proper and should give the Company the opportunity to earn a fair rate of return on its investment to which it is entitled.

Additions:	
Utility Plant in Service	$468,507,509
Construction Work in Progress	6,536,531
Working Capital	12,201,210
Total Additions	**$487,245,250**

Deductions:	
Accumulated Depreciation	$199,411,506
Accumulated Deferred Income Taxes	23,313,096
Customer Advances for Construction	187,175
Contributions in Aid of Construction	4,473,546
Total Deductions	**$227,385,323**
Rate Base	**$259,859,927**

Revenues and Expenses

The parties have stipulated to certain facts which were obtained by their review and investigation of the Company's books and records for the purposes of this case. The parties agree that the net operating income at present rates of the Company for the attrition period is $15,602,433 as detailed below. The TRA finds that the net operating income in this case has been adjusted to reflect the appropriate attrition period level of revenues and expenses necessary for continued utility operations.

Revenues:	
Sales and Transportation of Gas	$195,481,680
Less Gas Cost	115,869,340
Net Sale and Transportation of Gas	$79,612,340
Other Revenues	1,814,896
Total Net Revenues	**$81,427,236**
Expenses:	
Salaries and Wages	$17,721,485
Distribution Expense	5,062,890
Uncollectible Accounts Expense	850,872
Customer Relations Expense	657,174
Administrative and General Expense	10,526,781
Interest on Customer Deposits	232,103
Miscellaneous Expense	38,184
Depreciation & Amortization Expense	18,232,156
Taxes Other Than Income	8,938,625
State Excise Tax	678,624
Federal Income Tax	3,233,982
Total Expenses	**$66,172,876**
Allowance for Funds Used During Construction	$348,073
Net Operating Income	**$15,602,433**

Fair Rate of Return

In reaching a decision on a rate of return, the Authority must conduct an in-depth analysis and give proper consideration to numerous factors, such as capital structure, cost of capital and changes which can reasonably be anticipated in the foreseeable future. The Authority has the obligation to make this determination based upon the controlling legal standard set forth in the landmark cases of *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*[4] and *Federal Power Commission v. Hope Natural Gas Company,*[5] which have been specifically relied upon by the Tennessee Supreme Court.[6]

In the *Bluefield* case, the United States Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[7]

Later, in the *Hope* case, the United States Supreme Court refined these guidelines, holding that:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital

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[4] *Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia,* 262 U.S. 679, 43 S Ct 675 (1923)

[5] *Federal Power Commission v Hope Natural Gas Company*, 320 U S 591, 64 S. Ct. 281 (1944)

[6] *Southern Bell Telephone & Telegraph Co v Public Service Commission*, 304 S W 2d 640, 647 (Tenn 1957)

[7] *Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U S 679, 692-93, 43 S Ct 675, 679 (1923)

> costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.[8]

The parties for this case, and this case only, have agreed on a capital structure and cost that produces an overall rate of return for the Company of 8.42% without providing detail as to the specific structural components of this return. The TRA finds that this return is fair and reasonable and meets the tests of the *Bluefield* and *Hope* cases.

Revenue Deficiency

Based upon the rate base, net operating income, and fair rate of return agreed to by the parties, the revenue deficiency for this case is calculated to be $10,300,000 as shown below. This revenue deficiency calculation was agreed to by each of the parties. The TRA finds that the Company needs additional annual revenues in the amount of $10,300,000 in order to earn a fair return on its investment during the attrition year.

Rate Base	$259,859,927
Fair Rate of Return	8.42%
Required Net Operating Income	**$21,880,207**
Current Net Operating Income	15,602,433
Net Operating Income Deficiency	$6,277,774
Revenue Conversion Factor	1.640709
Net Revenue Deficiency	**$10,300,000**

[8] *Federal Power Commission v Hope Natural Gas Company*, 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944)

Rate Design

The parties stipulated to a rate design that will produce additional revenues of approximately $10,300,000 as shown on **Attachment A** to this Order. Based upon a review of the rate design set forth in **Attachment A**, the testimony and exhibits of the parties that were filed in this matter prior to the filing of the stipulated rate design, and the record as a whole, a majority of the panel finds that this rate design is just and reasonable and meets the standards set out in Tenn. Code Ann. § 65-5-203(a).

	Present Net Revenues	**Rate Increase %**	**Rate Increase**
Residential	$51,021,291	16.51%	$7,229,179
Commercial	28,974,173	5.44%	1,494,901
Industrial	8,820,079	18.62%	1,384,350
Special Contract	752,415	0.00%	0
Sale for Resale	169,200	6.19%	9,867
Other	2,129,609	10.92%	209,635
Total	**$91,866,767**	**12.67%**	**$10,327,932**
Revenue Deficiency			10,300,000
Difference			**$27,932**

Tariff and Service Regulation Changes

The parties have also stipulated to changes other than rates in the Company's tariff. Specifically, the parties have agreed on language to segment residential customers into one of two categories: a Standard Rate or low base usage category, and a Value Rate or high base load usage category. In addition, the parties have also agreed on language to segment commercial customers into one of four categories: a Low Usage Standard Rate, a Low Usage Value Rate, a Medium Usage Standard Rate and a Medium Usage Value Rate. These changes are also outlined in **Attachment A** to this Order.

In addition, the parties have agreed on tariff language to change the reconnection fee from a year-round rate of $50 to a seasonal design of $85 for reconnections during the time period from September through January and $55 for reconnections during the time period from February through August.

Finally, the parties have agreed on language for changes in the Company's service line policy. Under the current service line policy, the Company will extend its service lines for one hundred (100) feet from the main to the customer's premise at no additional charge if the customer agrees to use natural gas for one major appliance, and install an additional fifty (50) feet at no cost for each additional natural gas appliance. The new language eliminates the provision of installing an additional fifty (50) feet and replaces it with language stating that the additional service line will be installed at no cost only if the anticipated load from the additional appliance provides a reasonable return to the Company.

The Authority finds that these tariff changes are just and reasonable and meet the standards set out in Tenn.Code Ann. § 65-5-203(a).

Fixed Demand Cost Reallocation

Although not part of the base rates established in this case, the parties have stipulated to an allocation of fixed demand costs that the Company will recover through the purchased gas adjustment ("PGA") process as shown on **Attachment A** to this Order. The TRA finds that this fixed demand cost allocation is just and reasonable and meets the standards set out in Tenn. Code Ann. § 65-5-203(a).

Weather Normalization Adjustment

The parties have stipulated to use the "R" values, base load factors, and heat factors as set out below in future rate adjustments under the Company's Weather Normalization Adjustment.[9] The TRA finds that these factors are just and reasonable and meet the standards set out in Tenn. Code Ann. § 65-5-203(a).

	"R" Value ($/Therm)	Heat Sensitivity Factor (Therms/DDD)	Base Factor (Therms/month)
Residential:			
Standard Rate	$0.32000	$0.15957	$3.915640
Value Rate	0.32000	0.21337	23.086530
Commercial:			
Rate 302			
All Usage	0.35400	0.79247	0.675169
Rate 332			
First 2,000 Therms	0.35400	0.51840	486.221100
Over 2,000 Therms	0.35400	0.51840	486.221100
Rate 352			
All Usage	0.35400	17.6718	2229.587600
Rate 362			
First 5,000 Therms	0.35400	5.36775	6229.705300
Over 5,000 Therms	0.35400	5.36775	6229.705300

[9] These values and factors are defined in Service Schedule No 315 of the Weather Normalization Adjustment Rider in NGC's tariff which is on file with the Authority

IT IS THEREFORE ORDERED THAT:

1. The *Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges, For Approval of Revised Tariffs and Approval of Revised Service Regulations,* as modified by the *Stipulation,* is approved based on the Authority's determination that a rate increase is warranted and that NGC is entitled to a rate increase of $10,300,000.

2. The rate design set forth in **Attachment A** to this Order shall be used to allocate the approved $10,300,000 rate increase.

3. Any party aggrieved by the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within fifteen (15) days from the date of this Order.

4. Any party aggrieved by the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty (60) days from the date of this Order.

Pat Miller, Director

Sara Kyle, Director

Ron Jones, Director[10]

[10] Director Jones voted with the panel on the issue of the rate increase but did not vote with the majority on the issue of rate design

ATTACHMENT A

	Base Rate	Demand Rate
Residential		
Value Tariff (Rate 301)		
Winter Monthly Customer Charge	$13.0000	
Summer Monthly Customer Charge	10.0000	
Winter Volumetric Charge (per Therm)	0.3200	$0.02200
Summer Volumetric Charge (per Therm)	0.2700	0.01002
Standard Tariff (Rate 321)		
Winter Monthly Customer Charge	$13.0000	
Summer Monthly Customer Charge	10.0000	
Winter Volumetric Charge (per Therm)	0.3200	$0.05994
Summer Volumetric Charge (per Therm)	0.2700	0.01001
Commerical		
SGS Value Tariff (Rate 332)		
Monthly Customer Charge	$29.0000	
Winter – 1st 2000 Therms	0.3540	$0.02200
Winter – Over 2000 Therms	0.3540	0.01100
Summer – 1st 2000 Therms	0.3030	0.01500
Summer – Over 2000 Therms	0.3030	0.00750
SGS Standard Tariff (Rate 302)		
Monthly Customer Charge	$29.0000	
Winter Volumetric Charge (per Therm)	0.3540	$0.05994
Summer Volumetric Charge (per Therm)	0.3030	0.01000
MGS Value Tariff (Rate 362)		
Monthly Customer Charge	$75.0000	
Winter – 1st 5000 Therms	0.3540	$0.02200
Winter – Over 5000 Therms	0.3540	0.01100
Summer – 1st 5000 Therms	0.3030	0.01500
Summer – Over 5000 Therms	0.3030	0.00750
MGS Standard Tariff (Rate 352)		
Monthly Customer Charge	$75.0000	
Winter Volumetric Charge (per Therm)	0.3540	$0.02200
Summer Volumetric Charge (per Therm)	0.3030	0.01100

	Base Rate	Demand Rate
Industrial		
Industrial Sales (Rate 303)		
Customer Charge	$300.0000	
Demand Charge	8.0000	$0.54409
1st 15000 Therms	0.9742	0.00300
Next 25000 Therms	0.8953	0.00200
Next 50000 Therms	0.6450	0.00120
Over 90000 Therms	0.2764	0.00000
Industrial Transportation (Rate 313)		
Customer Charge	$300.0000	
Demand Charge	8.0000	$0.54409
1st 15000 Therms	0.9742	0.00300
Next 25000 Therms	0.8953	0.00200
Next 50000 Therms	0.6450	0.00120
Over 90000 Therms	0.2764	0.00000
Interruptible Sales (Rate 304)		
Customer Charge	$300.0000	
1st 15000 Therms	0.9742	$0.04500
Next 25000 Therms	0.8953	0.02000
Next 50000 Therms	0.6450	0.01500
Over 90000 Therms	0.2764	0.01000
Interruptible Transportation (Rate 314)		
Customer Charge	$300.0000	
1st 15000 Therms	0.9742	$0.00300
Next 25000 Therms	0.8953	0.00200
Next 50000 Therms	0.6450	0.00120
Over 90000 Therms	0.2764	0.00000
Special Contract	Set by Order	$0.09200
Sale for Resale (Rate 310)		
Demand	$8.0000	$0.54409
Commodity	0.9000	0.00171

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

BASS
BERRY • SIMS PLC

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December 22, 2011

VIA HAND DELIVERY

Chairman Kenneth C. Hill
c/o Sharla Dillon
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

Re: ***Petition of Piedmont Natural Gas Company, Inc. Inc., for an Adjustment to Its Rates, Approval of Changes to Its Rate Design, Amortization of Certain Deferred Assets, Approval of New Depreciation Rates, Approval of Revised Tariffs and Service Regulations, and Approval of a New Energy Efficiency Program and GTI Funding*, Docket No. 11-00144**

Dear Chairman Hill:

Enclosed please find an original and five (5) copies of the Stipulation and Settlement Agreement Between Piedmont Natural Gas Company, Inc. and the Consumer Advocate and Protection Division.

This material is also being filed today by way of email to the Tennessee Regulatory Authority docket manager, Sharla Dillon. Please file the original and four copies of this material and stamp the additional copy as "filed." Then please return the stamped copy to me by way of our courier.

Should you have any questions concerning this matter, please do not hesitate to contact me at the email address or telephone number listed above.

Sincerely,

David Killion

Enclosures

cc: Mr. David Foster, Chief of Utilities Division (w/o enclosure)
Mr. Jerry Kettles, Chief of Economic Analysis & Policy Division (w/o enclosure)
Ryan McGehee, Esq. (via email w/ enclosure)
C. Scott Jackson, Esq. (via email w/ enclosure)

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Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT TO ITS RATES, APPROVAL OF CHANGES TO ITS RATE DESIGN, AMORTIZATION OF CERTAIN DEFERRED ASSETS, APPROVAL OF NEW DEPRECIATION RATES, APPROVAL OF REVISED TARIFFS AND SERVICE REGULATIONS, AND APPROVAL OF A NEW ENERGY EFFICIENCY PROGRAM AND GTI FUNDING	)	DOCKET NO. 11-00144

STIPULATION AND SETTLEMENT AGREEMENT BETWEEN PIEDMONT NATURAL GAS COMPANY, INC. AND THE CONSUMER ADVOCATE AND PROTECTION DIVISION

Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company") and Robert E. Cooper, Jr., the Tennessee Attorney General and Reporter, through the Consumer Advocate and Protection Division ("Consumer Advocate") (collectively the "Parties"), constituting all of the parties to the above-captioned general rate proceeding and in comprehensive settlement of the matters at issue therein, do hereby stipulate and agree as follows:

BACKGROUND

1. Piedmont is incorporated under the laws of the State of North Carolina and is duly domesticated and engaged in the business of transporting, distributing and selling natural gas in the States of Tennessee, North Carolina and South Carolina. Piedmont's principal office and place of business is located at 4720 Piedmont Row Drive, Charlotte, North Carolina.

2. Piedmont is a public utility in Tennessee and its natural gas distribution business is subject to regulation and supervision by the Tennessee Regulatory Authority ("TRA" or the "Authority") pursuant to Chapter 4 of Title 65 of the Tennessee Code Annotated.

3. Piedmont is engaged in the business of distributing natural gas to customers located in Nashville and the remainder of Davidson County as well as portions of the adjoining counties of Cheatham, Dickson, Robertson, Rutherford, Sumner, Trousdale, Williamson, and Wilson and in certain incorporated towns and cities located therein. Piedmont has not filed for a rate increase with the Authority since 2003.

4. On September 2, 2011, Piedmont filed a petition for adjustment of its rates and charges, approval of changes to its rate design, amortization of certain deferred assets, approval of new depreciation rates, approval of revised tariffs and service regulations, and approval of a new energy efficiency program and Gas Technology Institute ("GTI") funding. In its petition, Piedmont sought an increase in its annual revenues of $16,712,711, an increase of 8.9%.

5. On September 21, 2011, the Consumer Advocate filed a Petition to Intervene in this proceeding which was allowed by Authority order dated September 29, 2011 without an objection. No other entity has sought or been granted party status in this proceeding.

6. Since the filing of Piedmont's petition, the parties to this proceeding have engaged in substantial discovery, informal information exchanges and extensive communication. In addition to the information provided pursuant to the Authority's Minimum Filing Requirements, Piedmont has responded to 85 data requests from the Authority's Staff and 55 data requests from the Consumer Advocate. Piedmont representatives and representatives from the Consumer Advocate have also spent a significant amount of time discussing the various aspects of Piedmont's rate case.

7. On December 6, 2011, the Consumer Advocate filed testimony in this proceeding challenging several aspects of Piedmont's petition, including the requested revenue increase. In this testimony, witnesses for the Consumer Advocate recommended a number of changes to the relief sought by Piedmont, including a proposed reduction in Piedmont's attrition period revenue requirement. The Consumer Advocate proposed a revenue increase of $9.863 million, an amount $6.849 million less than that proposed by Piedmont.

SETTLEMENT

8. Following Piedmont's review of the Consumer Advocate's testimony, representatives of Piedmont and the Consumer Advocate met by phone and in-person to discuss the possibility of a settlement in this proceeding.

9. Based on the exchange of information and discussions described above, and in order to resolve all disputed issues in this case through settlement and avoid the need for further litigation, Piedmont and the Consumer Advocate have agreed to certain adjustments to Piedmont's filing, including adjustments to its proposed revenues, expenses, net operating income, net operating income for return, rate base, and return on rate base, among others. Piedmont and the Consumer Advocate have also agreed to the disposition of a variety of non-rate matters at issue in this proceeding. Piedmont's and the Consumer Advocate's agreements encompass the matters discussed below.

10. Attrition Period. Piedmont and the Consumer Advocate agree that the appropriate attrition period for use in this proceeding is the 12 months ended February 28, 2013.

11. Revenue Deficiency. The adjustments to Piedmont's filed case described in paragraph 9 above collectively reduce Piedmont's attrition period revenue deficiency from

$16,712,711, an increase of 8.9%, to $11,900,000, an increase of 6.3%, and are based upon agreed changes to certain components of Piedmont's working capital, accumulated deferred income taxes, federal and state income tax expense, operating revenues, cost of gas, operations and maintenance expense, operating income, and return on common equity. Subject to Authority approval, Piedmont and the Consumer Advocate agree that this reduction in Piedmont's attrition period revenue deficiency is reasonable and appropriate.

12. Annualized Throughput. Piedmont and the Consumer Advocate agree that the appropriate level of attrition period throughput used herein, and reflected on Attachment B hereto, is 28,816,792 dekatherms, consisting of 18,370,260 dekatherms of tariff sales quantities, 9,901,819 dekatherms of tariff transportation quantities, and 544,713 dekatherms of special contract quantities.

13. Revenue Requirement. Piedmont and the Consumer Advocate agree that Piedmont's attrition period cost of service should include the components set forth on Attachment A hereto, which Piedmont and the Consumer Advocate agree are fair and reasonable to Piedmont and its customers and which include the following:

a. Required Operating Income of $27,824,920;

b. A rate base of $ 348,872,819;

c. An overall rate of return of 7.98%;

d. A return on common equity of 10.2%;

e. A capital structure consisting of 5.87% short-term debt, 41.42% long-term debt, and 52.71% equity.

f. A cost of short-term debt of 1.59%;

g. A cost of long-term debt of 6.05%;

h. A cost of common equity of 10.2%;

14. Amortization of Deferred Costs. Embedded within the cost of service described above, Piedmont and the Consumer Advocate also agree that it is appropriate to provide for the 8-year amortization of certain deferred regulatory assets and rate case expense in the following annual amounts:

a. $2,686,343 in deferred defined benefit pension costs as authorized by Authority Order dated June 9, 1997 in Docket No. 96-00977;

b. $243,760 in deferred environmental clean-up costs as authorized by Tennessee Public Service Commission Order dated December 21, 1992 in Docket No. 92-16160;

c. $119,963 in deferred flood response costs as authorized by Authority Order dated November 10, 2010 in Docket No. 10-00185; and

d. $89,983 in rate case expense incurred by Piedmont in conjunction with this case.

15. Rates. Piedmont and the Consumer Advocate agree that the rates reflected on Attachment B are fair and reasonable and appropriate for use in this proceeding.

16. Piedmont and the Consumer Advocate further stipulate and agree:

a. That the rate design set forth on Attachment B hereto, including the constituent components of rates for each of Piedmont's customer classes, is fair and reasonable and appropriate for use in this proceeding;

b. That the Company shall revert to filing for adjustments to fixed gas cost recovery through the PGA going forward;[1]

[1] The representation of fixed gas cost recovery rates as set forth on Attachment B is reasonable and appropriate in order to align with the elimination of the standard/value customer class distinction and the elimination of step rates in the small and medium general service classifications.

c. That the WNA factors and normal heating degree days set forth on Attachments C and D hereto are fair and reasonable and appropriate for use in this proceeding and should be approved by the Authority to be effective March 1, 2012;

d. That the period to which the WNA adjustment should apply going forward consists of the months of October through April of each year;

e. That the depreciation rates set forth in the depreciation study filed by Piedmont witness Rhonda Watts are fair and reasonable and appropriate for use in this proceeding and should be approved by the Authority to be effective March 1, 2012;

f. That for purposes of future defined benefit pension expense and environmental clean-up expense incurred by Piedmont, the deferral mechanisms established pursuant to Authority Order dated June 9, 1997 in Docket No. 96-00977 and Tennessee Public Service Commission Order dated December 21, 1992 in Docket No. 92-16160 should remain in effect;

g. That pursuant to Authority Order dated April 24, 2007 in Docket No. 03-00209, uncollectible gas costs should continue to be addressed through Piedmont's PGA mechanism and that no such costs are included in the revenue requirement or rates stipulated herein;

h. That pending Piedmont's next general rate proceeding, the appropriate AFUDC rate applicable to future investment in rate base by Piedmont is the overall rate of return on rate base stipulated herein;

i. That no funding of GTI research or implementation/funding of Piedmont's proposed School Energy Pledge Program will occur or be recovered from Piedmont's customers in conjunction with this case;

j. That the revised rate schedules and service regulations attached hereto as Attachment E are fair and reasonable and should be approved by the Authority to be effective March 1, 2012;

17. Piedmont also agrees to reduce the commodity gas cost component of Piedmont's PGA mechanism in conjunction with the other rate changes agreed to herein and to implement such reduction in rates on February 1, 2012.[2]

18. The Parties hereby agree that the revised rates, tariffs, rate schedules, and service regulations agreed to herein, both individually and in the aggregate, are fair and reasonable to all customer classes and will provide Piedmont with a reasonable opportunity to recover the agreed upon operating revenue requirement and a reasonable rate of return on investment.

19. The Parties agree to support this Stipulation and Settlement Agreement before the Authority and in any hearing, proposed order, or brief conducted or filed in this proceeding; provided, however, that the settlement of any issue provided for herein shall not be cited as precedent by any of the stipulating Parties hereto in any unrelated or separate proceeding or docket before the Authority. The resolution of issues reflected herein is the result of give and take negotiations between the Parties and does not necessarily reflect the position of any single Party on any discrete issue. None of the signatories hereto shall be deemed to have acquiesced in any ratemaking or procedural principle, including without limitation, any cost of service determination or cost allocation or revenue related methodology and neither Party waives its right to take positions with respect to the matters settled herein in future proceedings before the Authority. This Stipulation and Agreement shall not have any precedential effect in any future

[2] Nothing within this Stipulation and Settlement Agreement should be construed as having any impact on the PGA Rule and practice of the Authority.

proceeding or be binding upon any of the settling Parties in this or any other jurisdiction except to the extent necessary to implement the provisions hereof.

20. The Parties agree that all pre-filed testimony and exhibits of the Parties (including pre-filed supplemental testimony and exhibits supporting this Stipulation and Settlement Agreement) may be admitted into evidence without objection and the Parties hereby waive their right to cross-examine all witnesses with respect to such pre-filed testimony and exhibits; provided, however, that should questions be asked of such witnesses by any person at the hearing of this matter (including any questions by Directors or Authority staff), the Parties may cross-examine any witness with respect to such questions consistent with the agreements set forth in this Stipulation and Agreement.

21. The provisions of this Stipulation and Settlement Agreement are agreements reached in compromise and settlement and solely for the purpose of resolving this docket without the need for further litigation.

22. The stipulations agreed to in this Stipulation and Settlement Agreement, which are the product of negotiations and substantial communication and compromise between the Parties, are just and reasonable and in the public interest. The Parties jointly recommend that the Authority issue an order adopting this Stipulation and Settlement Agreement in its entirety without modification.

23. If the TRA does not accept the Stipulation and Settlement Agreement in whole and as full and final settlement of the issues in this Docket, this Stipulation and Settlement Agreement shall terminate and the Parties shall not be bound by any position set forth in this Stipulation and Settlement Agreement. Should this Stipulation and Settlement Agreement terminate, it will be considered void and have no binding effect, and the signatories to this

Stipulation and Settlement Agreement reserve their rights to fully participate in all relevant proceedings notwithstanding their agreement to the terms of this Stipulation and Settlement Agreement. The provisions of this Stipulation and Settlement Agreement are not severable.

24. By agreeing to this Stipulation and Settlement Agreement, no Party waives any right to continue litigating this matter should the Stipulation and Settlement Agreement be rejected by the TRA in whole or in part.

25. No provision of this Stipulation and Settlement Agreement shall be deemed an admission of any Party.

26. The Parties agree to support this Stipulation and Settlement Agreement in any proceeding before the Authority in this Docket; however, the Parties further agree and request the Authority to order that the settlement of any issue pursuant to this Stipulation and Settlement Agreement shall not be cited by the Parties or any other entity as binding precedent in any other proceeding before the Authority or any court, state or federal.

27. The provisions of this Stipulation and Settlement Agreement do not necessarily reflect the positions asserted by any Party, and no Party to this Stipulation and Settlement Agreement waives the right to assert any position in any future proceeding except as expressly stipulated herein. This Stipulation and Settlement Agreement shall not have precedential effect in any future proceeding or be binding on any Party except to the limited extent necessary to implement the provisions hereof.

28. This Stipulation and Settlement Agreement shall be governed by and construed under the laws of the State of Tennessee, notwithstanding conflict of law provisions.

The foregoing is agreed and stipulated to this 21 st day of December, 2011.

PIEDMONT NATURAL GAS COMPANY, INC.

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ATTACHMENT A

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Settlement Attachment A

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Index to Schedules
For the 12 Months Ending February 28, 2013

	Schedule No.
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Rate Base	2
Income Statement at Current Rates	3
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Taxes Other Than Income Taxes	5
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Settlement Attachment A
Schedule 1

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Revenue Deficiency
For the 12 Months Ending February 28, 2013

Line No.	Category	Settlement
1	Rate Base	$348,872,819
2	Operating Income at Present Rates	$20,595,215
3	Earned Rate of Return (Line 2/Line 1)	5.90%
4	Cost of Capital	7.98%
5	Required Operating Income (Line 1*Line 4)	$27,824,920
6	Operating Income Deficiency (Line 5-Line 2)	$7,229,705
7	Gross Revenue Conversion Factor	1.645921
8	Revenue Deficiency (Line 6*Line 7)	$11,900,000

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Rate Base
For the 12 Months Ending February 28, 2013

Line No.	Category	Settlement
1	Utility Plant in Service	$713,852,981
2	Construction Work in Progress	$33,025,962
3	Utility Plant Capital Lease	$0
4	Limited-Term Utility Plant - Net	$0
5	Working Capital	$30,718,420
6	Deferred Maintenance	$0
7	Total Additions	$777,597,364
8	Accumulated Depreciation	$ 336,408,892
9		
10	Accumulated Deferred Income Taxes	$87,138,706
11	Customer Advances for Construction	$0
12	Contributions In Aid of Construction	$5,176,946
13	Unamortized Investment Tax Credit	$0
14	Utility Plant Acquisition Adj.	$0
15	Total Deductions	$428,724,544
16	Rate Base (Line 7 - Line 15)	$348,872,819

Settlement Attachment A
Schedule 3

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Income Statement at Current Rates
For the 12 Months Ending February 28, 2013

Line No.		Category		Settlement
1		Operating Revenues		$189,205,584
2		Cost of Gas		$94,601,622
3		Gross Margin		$94,603,962
4		Operations and Maintenance Expense		$40,114,764
5		Depreciation and Amortization Expense		$19,600,350
6		Taxes Other Than Income		$9,048,687
7		State Excise Tax		$1,273,299
8		Federal Income Tax		$6,376,169
9				$76,413,270
10		Interest On Customer Deposits		$412,591
11		AFUDC		$2,817,115
12		Net Operating Income for Return		$20,595,215

Settlement Attachment A
Schedule 4

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Operation & Maintenance Expenses
For the 12 Months Ending February 28, 2013

Line No.		Category		Settlement
1		Salaries and Wages		$18,068,459
2		Transmission & Distribution Expense		$5,631,656
3		Uncollectible Accounts Expense		$57,564
4		Other Customer Accounts Expense		$880,193
5		Administrative and General		$15,358,729
6		Sales Expense		$118,163
7		Total O&M Expense		$40,114,764

Settlement Attachment A
Schedule 5

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Taxes Other Than Income Taxes
For the 12 Months Ending February 28, 2013

Line No.	Category	Settlement
1	Other General Taxes	$5,243
2	Gross Receipts Tax	$1,485,070
3	Property Taxes	$5,218,572
4	Franchise Tax	$930,057
5	Payroll Taxes	$1,409,745
6	Total Taxes Other Than Income Taxes	$9,048,687

Piedmont Natural Gas Company, Inc.
Docket No. 20-00000
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Excise and Income Taxes
For the 12 Months Ending February 28, 2013

Line No.		Category		Settlement
1		Operating Revenues		$94,603,962
2		Salaries and Wages		$18,068,459
4		Transmission & Distribution Expense		$5,631,656
5		Uncollectible Accounts Expense		$57,564
6		Other Customer Accounts Expense		$880,193
7		Administrative and General		$15,358,729
8		Sales Expense		$118,163
9		Depreciation and Amortization Expense		$19,600,350
10		Taxes Other Than Income		$9,048,687
11		NOI Before Excise and Income Taxes		$25,840,160
12		AFUDC		$2,817,115
13		Interest Expense		($9,068,052)
14		Pre-tax Book Income		$19,589,223
15		Schedule M Adjustments		$0
16		Excise Taxable Income		$19,589,223
17		Excise Tax Rate		6.50%
18		Excise Tax Expense		1,273,299
19		Excise Tax NOL		-
20				1,273,299
21				19,589,223
22				-
23		Excise Tax		(1,273,299)
24		Schedule M Adjustments		-
25		FIT Taxable Income		18,315,923
26		FIT Rate		35.00%
27		Federal Income Tax Expense		6,410,573
28		ITC Amortization		($34,404)
29		Federal Income Tax Expense		6,376,169

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Revenue Conversion Factor
For the 12 Months Ending February 28, 2013

Line No.	Category		Settlement
1	Operating Revenues		1.000000
2	Add: Forfeited Discounts	-	-
3	Balance		1.000000
4	Uncollectible Ratio	0.0003	0.000308
5	Balance		0.999692
6	State Excise Tax	0.0650	0.064980
7	Balance		0.934712
8	Federal Income Tax	0.3500	0.327149
9	Balance		0.607563
10	Revenue Conversion Factor (Line 1 / Line 11)		1.645921

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Cost of Capital
For the 12 Months Ending February 28, 2013

Line No.	Final Capital Structure	Ratio	Cost	Weighted Cost	Tax Deductible
1	Short Term Debt	5.87%	1.59%	0.093%	0.093%
2	Long Term Debt	41.42%	6.05%	2.506%	2.506%
3	Common Equity	52.71%	10.20%	5.376%	
4	Total	100.00%		7.98%	2.599%

ATTACHMENT B

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
Proposed Rates and Revenues by Rate Schedule

Settlement Attachment B
Schedule 1

(dekatherms) Rate Schedule	Attrition Period Billing Determinants (1)	"Clean" Billing Rates (2)	Proposed Revenues (3)	Proposed Margin Rates (4)	Proposed Margin (5)	Proposed PGA Demand Rates (6)	Proposed PGA Demand (7)	Current PGA Commodity Rates (8)	Current PGA Commodity (9)
Residential - 301									
Bills - winter (Nov - Mar)	760,041	17.45	$13,262,715	17.45	$13,262,715				
Bills - summer (Apr - Oct)	1,055,850	13.45	$14,201,163	13.45	$14,201,163				
Winter (Nov - Mar)	9,068,898	8.29400	$75,217,440	3.20000	$29,020,474	0.32800	$2,974,599	4.76600	$43,222,368
Summer (Apr - Oct)	2,061,316	7.79400	$16,065,897	2.70000	$5,565,553	0.32800	$676,112	4.76600	$9,824,232
Total	11,130,214		$118,747,235		$62,049,925		$3,650,711		$53,046,600
Total Residential									
Bills	1,815,891		$27,463,898		$27,463,898		$0		$0
DTs	11,130,214		$91,283,337		$34,586,027		$3,650,711		$53,046,600
Small General - 302									
Bills	198,023	44.00	$8,713,012	44.00	$8,713,012				
Winter (Nov - Mar)	3,744,501	8.63400	$32,330,022	3.54000	$13,255,534	0.32800	$1,228,196	4.76600	$17,846,292
Summer (Apr - Oct)	1,353,699	8.09400	$10,956,840	3.00000	$4,061,097	0.32800	$444,013	4.76600	$6,451,729
Total	5,098,200		$51,999,874		$26,029,643		$1,672,209		$24,298,021
Medium General - 352									
Bills	4,924	225.00	$1,107,900	225.00	$1,107,900				
Winter (Nov - Mar)	1,150,745	8.63400	$9,935,532	3.54000	$4,073,637	0.32800	$377,444	4.76600	$5,484,451
Summer (Apr - Oct)	416,013	8.09400	$3,367,209	3.00000	$1,248,039	0.32800	$136,452	4.76600	$1,982,718
Total	1,566,758		$14,410,641		$6,429,576		$513,896		$7,467,169
Total Commercial									
Bills	202,947		$9,820,912		$9,820,912		$0		$0
DTs	6,664,958		$66,410,515		$32,459,219		$2,186,105		$31,765,190
Large General Sales Service - 303									
Bills	475	800.00	$380,000	800.00	$380,000				
Demand dt	61,947	12.92520	$800,679	8.0000	$495,577	4.92520	$305,102	0.00000	$0
First 1,500 dt	373,595	5.73420	$2,142,268	0.9682	$361,715		$0	4.76600	$1,780,554
Next 2,500 dt	136,761	5.66130	$774,245	0.8953	$122,442		$0	4.76600	$651,803
Next 5,000 dt	43,004	5.41100	$232,695	0.6450	$27,738		$0	4.76600	$204,957
Over 9,000 dt	9,488	5.04240	$47,842	0.2764	$2,622		$0	4.76600	$45,220
Total	562,848		$4,377,729		$1,390,094		$305,102		$2,682,534
Interruptible Sales Service - 304									
Bills	15	800.00	$12,000	800.00	$12,000				
First 1,500 dt	1,928	5.73420	$11,056	0.9682	$1,867		$0	4.76600	$9,189
Next 2,500 dt	0	5.66130	$0	0.8953	$0		$0	4.76600	$0
Next 5,000 dt	0	5.41100	$0	0.6450	$0		$0	4.76600	$0
Over 9,000 dt	0	5.04240	$0	0.2764	$0		$0	4.76600	$0
Total	1,928		$23,056		$13,867		$0		$9,189
Firm Transportation Service - 313									
Bills	1,021	800.00	$816,800	800.00	$816,800				
Demand dt	157,725	12.92520	$2,038,623	8.0000	$1,261,798	4.92520	$776,826	0.00000	$0
First 1,500 dt	1,080,164	0.96820	$1,045,815	0.9682	$1,045,815		$0	0.00000	$0
Next 2,500 dt	548,397	0.89530	$490,980	0.8953	$490,980		$0	0.00000	$0
Next 5,000 dt	170,738	0.64500	$110,126	0.6450	$110,126		$0	0.00000	$0
Over 9,000 dt	6,421	0.27640	$1,775	0.2764	$1,775		$0	0.00000	$0
Total	1,805,720		$4,504,119		$3,727,294		$776,826		$0
Interruptible Transportation Service - 314									
Bills	653	800.00	$522,400	800.00	$522,400				
First 1,500 dt	863,471	0.96820	$836,013	0.9682	$836,013		$0	0.00000	$0
Next 2,500 dt	973,339	0.89530	$871,430	0.8953	$871,430		$0	0.00000	$0
Next 5,000 dt	1,099,176	0.64500	$708,969	0.6450	$708,969		$0	0.00000	$0
Over 9,000 dt	5,160,113	0.27640	$1,426,255	0.2764	$1,426,255		$0	0.00000	$0
Total	8,096,099		$4,365,067		$4,365,067		$0		$0
Total Large Volume									
Bills	2,164		$1,731,200		$1,731,200		$0		$0
Demand	219,672		$2,839,302		$1,757,375		$1,081,928		$0
DTs	10,466,595		$13,269,971		$9,496,322		$1,081,928		$2,691,723
Resale Service - 310									
Bills	31								
Demand	2,400	12.92520	$31,020	8.00000	$19,200	4.92520	$11,820	0.00000	$0
Commodity	10,312	5.66600	$58,428	0.9000	$9,281		$0	4.76600	$49,147
Special Contracts (1)	544,713		$607,737		$489,532		$118,205		
Bills									
TOTAL THROUGHPUT - SALES CUSTOMERS	18,370,260		$189,647,983		$95,941,586		$6,153,738		$87,552,660
TOTAL THROUGHPUT - TRANSPORTATION CUSTOMERS	9,901,819		$8,869,166		$8,092,161		$776,826		$0
TOTAL THROUGHPUT - SPECIAL CONTRACTS	544,713		$607,737		$489,532		$118,205		$0
TOTAL	28,816,792		$199,124,906		$104,523,479		$7,048,769		$87,552,660
OTHER REVENUES			$1,980,666		$1,980,666				
GRAND TOTAL OPERATING REVENUES			$201,105,572		$106,504,145				
PROFORMA OPERATING REVENUES PER WILLIAM H. NOVAK (2)			$189,205,584		$94,603,962				
REVENUE ADJUSTMENT			$11,899,988		$11,900,183				

(1) Includes only the two Tennessee Regulatory Authority ("Authority") approved special contracts currently in place, which are Bridgestone and DuPont. These special contracts were approved by the Authority, respectively, in Docket Nos. 10-00015 and 10-00142.
(2) Attrition Period Revenue per William H. Novak Direct Testimony, Attachment WHN-4, Schedule 1, Line 14.

PIEDMONT NATURAL GAS COMPANY, INC.
Tennessee Service Territory
Billing Rates Effective: March 1, 2012

Rate Schedule	Description	Tariff Rate Approved In Docket No. 11-00144	Cumulative PGA Demand	Cumulative PGA Commodity	Current Refund	Current ACA Demand	Current ACA Commodity	Current IPA	Total Adj. Factor (Sum Col.2 thru Col.6)	Proposed Billing Rate (Col.1+Col.7)
		<1>	<2>	<3>	<4>	<5a>	<5b>	<6>	<7>	<8>
	Monthly Charge-Nov.-Mar.	$17.45								$17.45
Residential	Monthly Charge-Apr.-Oct.	$13.45								$13.45
301	Nov.- Mar. per TH	0.32000	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.84466
301	Apr.- Oct. per TH	0.27000	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.79466
Small General	Monthly Charge	$44.00								$44.00
302	Nov.- Mar. per TH	0.35400	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.87866
302	Apr.- Oct. per TH	0.30000	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.82466
Medium General	Monthly Charge	$225.00								$225.00
352	Nov.- Mar. per TH	0.35400	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.87866
352	Apr.- Oct. per TH	0.30000	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.82466
Natural Gas Vehicle Fuel	Monthly Charge	$40.00								$40.00
342	Rate per TH	0.23109	0.03280	0.47660	0.00000	0.03450	-0.02597	0.00673	0.52466	0.75575
342	Rate per GGE	0.29117	0.04133	0.60052	0.00000	0.04347	-0.03272	0.00848	0.66108	0.95225
303	Monthly Charge	$800.00								$800.00
Firm	Demand Charge per TH	0.80000	0.49252		0.00000	0.52652			1.01904	1.81904
General Sales	First 15,000 TH/TH	0.09682		0.47660	0.00000		-0.02597	0.00673	0.45736	0.55418
	Next 25,000 TH/TH	0.08953		0.47660	0.00000		-0.02597	0.00673	0.45736	0.54689
	Next 50,000 TH/TH	0.06450		0.47660	0.00000		-0.02597	0.00673	0.45736	0.52186
	Over 90,000 TH/TH	0.02764		0.47660	0.00000		0.00000	0.00673	0.48333	0.51097
304	Monthly Charge	$800.00								$800.00
Interruptible	First 15,000 TH/TH	0.09682		0.47660	0.00000		-0.02597	0.00673	0.45736	0.55418
General Sales	Next 25,000 TH/TH	0.08953		0.47660	0.00000		-0.02597	0.00673	0.45736	0.54689
	Next 50,000 TH/TH	0.06450		0.47660	0.00000		-0.02597	0.00673	0.45736	0.52186
	Over 90,000 TH/TH	0.02764		0.47660	0.00000		0.00000	0.00673	0.48333	0.51097
313	Monthly Charge	$800.00								$800.00
Firm	Demand Charge per TH	0.80000	0.49252		0.00000	0.52652			1.01904	1.81904
Transportation	First 15,000 TH/TH	0.09682			0.00000				0.00000	0.09682
	Next 25,000 TH/TH	0.08953			0.00000				0.00000	0.08953
	Next 50,000 TH/TH	0.06450			0.00000				0.00000	0.06450
	Over 90,000 TH/TH	0.02764			0.00000				0.00000	0.02764
314	Monthly Charge	$800.00								$800.00
Interruptible	First 15,000 TH/TH	0.09682			0.00000				0.00000	0.09682
Transportation	Next 25,000 TH/TH	0.08953			0.00000				0.00000	0.08953
	Next 50,000 TH/TH	0.06450			0.00000				0.00000	0.06450
	Over 90,000 TH/TH	0.02764			0.00000				0.00000	0.02764
310	Demand Charge per TH	0.80000	0.49252		0.00000	0.52770			1.02022	1.82022
Resale Service	Commodity Charge	0.09000		0.47660	0.00000		-0.02597	0.00673	0.45736	0.54736

NOTES:
1) In accordance with the Tennessee Public Service Commission order in Docket U-7074 customers metered inside Davidson County are required to pay an additional 6.93% for collection of the Metro Franchise Fee. Customers served by the Fairview, Greenbrier, Hartsville, Mt. Juliet and White House systems are required to pay 5.0%. Customers served by the Franklin and Nolensville systems are required to pay 3%. Commercial customers on the Ashland City system are required to pay 5%.

2) The Monthly Charge for Rate Schedule 342 is not applicable to gas service provided at the Company's Premises. The Company may bill in units of Gas Gallon Equivalent ("GGE") for gas service provided at the Company's Premises under Rate Schedule 342. The rates convert 1.26 Therms to 1 GGE.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

ATTACHMENT C

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

Piedmont Natural Gas Company, Inc.
TRA Docket #11-00144
WNA Factors effective March 1, 2012

Settlement Attachment C

Rate Schedule	November - March "R" Factor ($/Therm)	October & April "R" Factor ($/Therm)	Base Factor (BL) (Therms/DDD)	Heat Sensitivity Factor (HSF) (Therms/Month)
Residential - 301	0.32000	0.27000	0.17945	7.91318
Small & Medium General - 302 & 352	0.35400	0.30000	0.74873	104.85079

ATTACHMENT D

Piedmont Natural Gas Company, Inc.
TRA Docket # 11-00144
Nashville Heating Degree Days

Settlement Attachment D

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

NORMAL DAILY WEATHER FOR THE 30 YEAR PERIOD ENDING MAY 2011

DAY	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.57	22.67	19.40	11.23	2.77	0.30	0.00	0.00	0.00	2.33	7.67	20.77
2	24.30	22.67	17.57	8.73	2.63	0.13	0.00	0.00	0.00	2.77	9.80	21.10
3	24.20	24.20	19.03	8.47	4.27	0.13	0.00	0.00	0.00	3.20	11.60	20.00
4	24.43	26.30	16.40	10.00	4.47	0.13	0.00	0.00	0.00	2.73	12.10	21.37
5	25.93	27.10	16.70	11.03	2.97	0.07	0.00	0.00	0.03	3.07	12.70	23.37
6	24.60	26.67	16.77	10.70	2.27	0.10	0.00	0.00	0.13	3.50	14.80	24.47
7	25.73	26.47	17.13	9.33	1.73	0.10	0.00	0.00	0.03	4.77	13.43	23.63
8	27.50	25.47	16.33	8.37	1.87	0.00	0.00	0.00	0.00	4.33	12.70	21.77
9	26.37	25.30	17.53	10.13	1.63	0.00	0.00	0.00	0.00	3.67	11.50	21.50
10	26.77	25.30	18.87	9.03	1.73	0.07	0.00	0.00	0.00	3.73	13.27	22.53
11	28.20	24.33	17.17	6.40	1.47	0.00	0.00	0.00	0.00	4.33	13.80	22.60
12	25.37	25.50	15.63	6.47	1.20	0.03	0.00	0.00	0.00	4.27	15.60	23.63
13	25.73	24.70	14.67	6.63	1.70	0.17	0.00	0.10	0.10	4.43	15.40	23.17
14	27.57	21.77	15.03	5.50	1.63	0.00	0.00	0.00	0.23	5.33	14.50	22.40
15	28.57	21.57	13.63	7.10	1.70	0.00	0.00	0.00	0.10	4.93	14.67	22.30
16	28.30	21.63	13.93	7.47	2.20	0.00	0.00	0.00	0.33	5.87	15.97	23.80
17	27.90	22.50	12.77	7.50	1.77	0.00	0.00	0.00	0.47	5.77	16.83	23.30
18	28.43	21.13	11.53	6.03	1.57	0.00	0.00	0.00	0.33	5.80	15.37	25.20
19	29.43	20.53	12.63	4.93	1.33	0.00	0.00	0.00	0.60	7.50	12.83	26.23
20	29.30	17.83	12.57	4.60	1.17	0.00	0.00	0.00	0.53	7.73	14.47	26.80
21	29.07	16.47	14.97	5.13	1.30	0.03	0.00	0.00	1.27	6.17	16.77	25.30
22	26.70	19.50	14.70	4.53	1.20	0.03	0.00	0.00	1.53	6.70	17.57	24.70
23	26.30	19.37	12.80	5.20	0.43	0.00	0.00	0.00	1.80	7.47	16.67	26.00
24	26.00	20.33	12.00	4.93	0.27	0.00	0.00	0.00	1.80	8.53	17.57	28.43
25	27.93	21.10	11.27	3.97	0.63	0.00	0.00	0.00	1.27	8.10	15.93	31.37
26	29.00	20.57	11.37	4.07	0.27	0.00	0.00	0.00	1.60	7.70	15.03	28.70
27	27.97	19.70	11.03	4.70	0.47	0.00	0.00	0.00	2.07	9.03	14.60	23.33
28	25.70	20.80	10.33	4.63	0.47	0.00	0.00	0.03	1.83	9.50	17.30	22.77
29	23.83	*4.93*	10.90	3.80	0.67	0.00	0.00	0.07	2.10	8.53	18.30	24.47
30	24.33		11.33	2.70	0.53	0.00	0.00	0.00	2.20	7.10	18.90	24.17
31	25.40		10.90		0.43		0.00	0.00		6.03		22.50
Calendar Total	826	636	447	203	49	1	0	0	20	175	438	742
Cycle Total	798	806	518	324	108	16	0	0	1	77	311	579

NON-LEAP YEAR TOTAL	3,538
LEAP YEAR TOTAL	3,553

Note: Degree Days for February 29 must be multiplied by 4 to arrive at the true DDD for this day, for purposes of applying the WNA adjustment.

ATTACHMENT E

Piedmont Natural Gas Company, Inc.
Tennessee
Index of Tariff & Service Regulations

Rate Schedule 301	Residential Service
Rate Schedule 302	Small General Service
Rate Schedule 303	Large General Sales Service
Rate Schedule 304	Interruptible Sales Service
Rate Schedule 306	Schedule for Limiting and Curtailing Service
Rate Schedule 307	Balancing, Cash-Out, and Agency Authorization
Rate Schedule 309	Special Availability Service
Rate Schedule 310	Resale Service
Rate Schedule 311	Purchased Gas Adjustment Rider
Rate Schedule 312	Equal Payment Plan
Rate Schedule 313	Firm Transportation Service
Rate Schedule 314	Interruptible Transportation Service
Rate Schedule 315	Weather Normalization Adjustment (WNA) Rider
Rate Schedule 316	Performance Incentive Plan
Rate Schedule 342	Natural Gas Vehicle Fuel
Rate Schedule 352	Medium General Service

Appendix A - Customer Agent Agreement

Tennessee Service Regulations

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

RATE SCHEDULE NO. 301
Residential Service

AVAILABILITY
Gas Service under this Rate Schedule is available in the area served by the Company in the State of Tennessee, upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations, to any full requirements single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered where the Company's distribution mains are suitable for supplying the desired service. N

CHARACTER OF SERVICE
The nature of Service provided by Company to Customer under this Rate Schedule is firm sales Service. Rate Schedule 301 applies to all residential customers. N

MARGIN RATE	Winter (November-March)	Summer (April-October)	
Monthly Charge	$17.45	$13.45	I
Commodity Charge (per therm)	$.32000	$.27000	

MONTHLY CHARGE
A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge for gas delivered. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. T

COMMODITY CHARGE
The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

BACKUP SERVICE
When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Service Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. S

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and the Company's Service Regulations. S

WEATHER NORMALIZATION ADJUSTMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider."

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS
The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

RATE SCHEDULE NO. 302
Small General Service

AVAILABILITY

Gas Service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer, upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations, whose average daily usage is less than 20 dekatherms per day. Average daily gas usage will be based on the Customer's usage during the most recent past calendar year ended on December 31. Availability of this Rate Schedule for new Customers or for Customers without at least one full year of usage history will be based on reasonably anticipated usage. N

CHARACTER OF SERVICE

The nature of Service provided by Company to Customer under this Rate Schedule is firm sales Service. Any reclassification or change in quantity or character of Service to Customer will be subject to procedures set forth in the Company's Service Regulations. N

MARGIN RATE	Winter (November-March)	Summer (April-October)	
Monthly Charge	$44.00	$44.00	I
Commodity Charge (per therm)	$.35400	$.30000	R

MONTHLY CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge for gas delivered. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. T

COMMODITY CHARGE

The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

BACKUP SERVICE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Service Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. S

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No.306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. S

WEATHER NORMALIZATION ADJUSTMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider."

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS
The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

RATE SCHEDULE NO. 303
Large General Sales Service

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer whose average daily gas usage is reasonably anticipated to equal or exceed 500 therms per day. All Service under this Rate Schedule shall be contingent upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations. Upon commencement of Service under this Rate Schedule, any reclassification or change in quantity or character of Service to Customer shall be subject to the provisions of this Rate Schedule 303 and the procedures set forth in the Company's Service Regulations. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. N

CHARACTER OF SERVICE

The nature of Service provided by Company to Customer under this Rate Schedule is firm sales Service. N

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 309 concurrent with service provided under the Rate Schedule. Subject to the requirements set forth above, a Customer may, subject to the consent of the Company, elect to discontinue service under this Rate Schedule and receive service under Rate Schedule No.313 by giving written notice to the Company prior to March 1 of any year. The Company will not withhold such consent provided (a) the Company continues to offer large general transportation Service under Rate Schedule 313, (b) the Company is able to provide Service under Rate Schedule 313 under commercially reasonable terms and conditions, and (c) the analyses applicable to reclassifications or changes in Service set forth in the Company's Service Regulations support such consent. If timely notice is received from Customer and consent is provided by Company, the Customer shall discontinue service under this Rate Schedule and Company shall provide Service under Rate Schedule 313 effective the first June 1 following the notice. N

All gas delivered pursuant to this Rate Schedule shall be metered by the Company separately from any gas delivered to Customer under any of the Company's other Rate Schedules.

MARGIN RATE

Monthly Charge	$800.00	I
Demand Charge (per therm of billing demand)	$.80000	
Commodity Charge (per therm)		R
1st Step (0-15,000 therms)	$.09682	
2nd Step (15,001-40,000 therms)	$.08953	
3rd Step (40,001-90,000 therms)	$.06450	
4th Step (Over 90,000 therms)	$.02764	

EFFECTIVE: March 1, 2012

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

MONTHLY MINIMUM BILL
The minimum monthly bill shall be the Monthly Charge plus the monthly Demand Charge.

MONTHLY CHARGE
A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. T

BILLING DEMAND
The billing demand shall be determined as follows:

A Customer's billing demand determinant shall be the highest daily usage during the period from November 1 to March 31 of the previous winter period as metered and reported to the Company by the telemetering equipment installed by the Company. Changes to the Customer's billing demand determinant will become effective June 1 of each year. The per unit demand charge may be adjusted from time to time to reflect rate changes, including, but not limited to, a general change in system rates or a change in pipeline capacity charges billed to the Company.

For Customers commencing initial gas service under this Rate Schedule and who do not have a consumption history from other services provided by the Company, the billing demand determinant shall be the greater of: 1) the month of highest consumption for the period to date multiplied by six percent (6%), or 2) 500 therms. If a Customer has received gas service from the Company prior to receiving service under this rate schedule, but does not have daily telemetered records to determine peak day usage as described above, the Company shall determine a billing demand based upon the highest monthly level of consumption during the previous winter period multiplied by six percent (6%).

COMMODITY CHARGE
The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

SERVICE AGREEMENTS
All Customers purchasing gas under this Rate Schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. S

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Rate Schedule No.306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. S

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
CAD Data Request No. 1, Item 85

RATE SCHEDULE NO. 304
Interruptible General Sales Service

AVAILABILITY

Gas service under this rate schedule is available in the area served by the Company in the State of Tennessee **ON AN INTERRUPTIBLE BASIS** to any full requirements non-residential Customer whose average daily gas usage is reasonably anticipated to equal or exceed 500 therms per day. All Service under this Rate Schedule shall be contingent upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations. Upon commencement of Service under this Rate Schedule, any reclassification or change in quantity or character of Service to Customer shall be subject to the provisions of this Rate Schedule 304 and the procedures set forth in the Company's Service Regulations. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. N

CHARACTER OF SERVICE

The nature of Service provided by the Company to Customer under this Rate Schedule is interruptible sales service. N

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 309 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may, subject to the consent of the Company, elect to discontinue service under this Rate Schedule and receive service under Rate Schedule 314 by giving written notice to the Company prior to March 1 of any year. The Company will not withhold such consent provided (a) the Company continues to offer large general transportation Service under Rate Schedule 313, (b) the Company is able to provide Service under Rate Schedule 313 under commercially reasonable terms and conditions, and (c) the analyses applicable to reclassifications or changes in Service set forth in the Company's Service Regulations support such consent. If timely notice is received from Customer and consent is provided by Company, the Customer shall discontinue service under this Rate Schedule and Company shall provide Service under Rate Schedule 314 effective the first June 1 following the notice. N

Customers purchasing gas pursuant to this schedule shall maintain, in useable condition, alternate-fuel facilities with ample on-site alternate fuel capability for supplying 100% of the establishment's gas requirements during periods of gas interruption or curtailment. Such interruption or curtailment shall be immediately effective upon verbal or written notification by the Company, and Customer shall refrain from using gas until permitted to do so by the Company. It is understood and agreed that the Company will have the right to suspend gas service without further notice to the Customer in the event Customer fails to curtail Customer's use of gas in accordance with the Company's notice of curtailment.

All gas delivered pursuant to this Rate Schedule shall be metered by the Company separately from any gas delivered to Customer under any of the Company's other Rate Schedules. N

Reclassification of customers between rate schedules will be based upon procedures set forth in the Company's Service Regulations as approved by the Tennessee Regulatory Authority.

Piedmont Natural Gas Company, Inc.
Docket No. 20-00086
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MARGIN RATE

Monthly Charge	$800.00	I
Commodity Charge (per therm)		R
1st Step (0-15,000 therms)	$.09682	
2nd Step (15,001-40,000 therms)	$.08953	
3rd Step (40,001-90,000 therms)	$.06450	
4th Step (Over 90,000 therms)	$.02764	

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the Monthly Charge.

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge for gas delivered. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. T

COMMODITY CHARGE

The rate per therm shall be billed on the quantity of gas delivered by Company to Customer. N

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. S

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgment as to the available gas supply, Customer's load N

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factor or use pattern, end use, impact on the local economy, Company's Service Regulations and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and the Company's Service Regulations. S

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS N

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations.

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SERVICE SCHEDULE NO. 306
Schedule for Limiting and Curtailing Service

This Service Schedule defines the types of curtailment that the Company may invoke from time to time due to the occurrence of extreme weather conditions, operating conditions or force majeure events, and describes the process and procedures to be followed in the implementation of gas service restrictions.

DISTRIBUTION PRESSURE CURTAILMENTS

Due to extreme weather conditions, operating conditions or force majeure events as defined in the Company's Tennessee Service Regulations, Rules and Regulations Governing Supply and Consumption of Gas, or the demands of the Company's firm Customers as the same may effect the Company's ability to provide interruptible service, the Company may experience localized pressure deficiencies. During such times and within the areas affected, the Company will curtail service to interruptible Customers served under Rate Schedule No. 304, Rate Schedule No.309, or Rate Schedule 314, by priority of their margin contribution to the Company (curtailing Customers with the lowest margin rate first) until the pressure situation can be alleviated. In the unlikely event that further interruption is required, the Company will proceed with curtailment by margin contribution considering end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SUPPLY OR CAPACITY RELATED CURTAILMENTS

In situations when supply and capacity services contracted by the Company are not sufficient to meet the full requirements of Customers desiring sales services from the Company, the Company will first curtail service to interruptible sales Customers receiving service under Rate Schedule No. 304 by priority of their margin contribution to the Company. Customers receiving discounted sales service under Rate Schedule No. 309 will also be curtailed according to the discounted rates. The Company reserves the right at the Company's discretion to purchase quantities being delivered to the Company by Customers under Rate Schedule 314 at market prices in order to serve Customers without operable alternative fuel capability. In the unlikely event that further interruption is required, the Company will proceed with curtailment by margin contribution considering end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

EMERGENCY SERVICE

The Company will make every reasonable effort to deliver plant protection volumes to industrial and commercial Customers that do not have standby fuel systems sufficient to prevent damage to facilities or danger to personnel, or to Customers that find it impossible to continue operations on the Customer's standby or alternate energy source as a result of a bona fide existing or threatened emergency. This includes the protection of such existing material in process that would otherwise be destroyed, or deliveries required to maintain plant production. All emergency gas service is of a discretionary nature and implies no present or future obligation of the Company to any Customer to provide such service on either a temporary or continuing basis. Deliveries of gas hereunder shall be made pursuant only to advance operating arrangements between the Company's authorized personnel and the Customer and shall be subject to curtailment and interruption at any time should the Company deem it necessary.

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RATE FOR EMERGENCY SERVICE

If the Company has authorized the Customer to consume limited quantities of emergency gas as provided in the above paragraph, then all gas consumed by the Customer will be at a rate of $1.00 per therm plus the higher of two gas commodity indices, "Monthly Contract" and "Daily Price", until otherwise notified that either (1) further gas sales will be under the Customer's regular rate schedule or (2) complete curtailment is unavoidable and that further gas sales will be considered unauthorized. "Monthly Contract" shall be defined as the monthly contract index price for the applicable calendar month as published in Gas Daily under the designation, "Monthly Contract Index" and indicated specifically under "Citygates" for Tenn. Zone 6 (delivered)". "Daily Price" shall be defined as the daily price for gas defined by Gas Daily as stated in the "Daily Price Survey", "Citygates", "Tenn. Zone 6 (delivered)", "Midpoint" price. For Days of consumption when the "Monthly Contract Index" is not published, the "Monthly Contract Index" shall equal the corresponding "Daily Price" published for the first day of the month of flow. For days of consumption when the "Daily Price" is not published, the "Daily Price" shall equal the average of the corresponding index prices as published on the nearest preceding and nearest subsequent day. Revenues realized from emergency service transactions will be credited to the Actual Cost Adjustment (ACA) account as recovery of gas costs. C

UNAUTHORIZED OVER RUN PENALTY

If at any time a Customer exceeds specified contract entitlements or if during any curtailment period, any affected Customer takes, without the Company's advance written approval, a volume of natural gas in excess of the curtailment period quantity entitlement applicable to such Customer, said volume shall constitute an unauthorized over run volume. For each therm of such unauthorized over run volume taken by such Customer, such Customer shall pay to the Company a rate of $1.50 per therm plus the higher of two gas commodity indices, "Monthly Contract" and "Daily Price". "Monthly Contract" shall be defined as the monthly contract index price for the applicable calendar month as published in Gas Daily under the designation, "Monthly Contract Index" and indicated specifically under "Citygates" for Tenn. Zone 6 (delivered)". "Daily Price" shall be defined as the daily price for gas defined by Gas Daily as stated in the "Daily Price Survey", "Citygates", "Tenn. Zone 6 (delivered)", "Midpoint" price. For Days of consumption when the "Monthly Contract Index" is not published, the "Monthly Contract Index" shall equal the corresponding "Daily Price" published for the first day of the month of flow. For days of consumption when the "Daily Price" is not published, the "Daily Price" shall equal the average of the corresponding index prices as published on the nearest preceding and nearest subsequent day. The Customer shall be liable for the above charges together with and in addition to any incremental charges or assessments (including, but not limited to penalties) by the interstate pipeline during the time of the unauthorized usage by such Customer. The payment of a penalty for unauthorized over run volumes shall not under any circumstances be considered as giving any such Customer the right to take unauthorized over-run volumes, nor shall such payment be considered as a substitute for any other remedies available to the Company or any other Customer against the offending Customer for failure to adhere to its obligations under the provisions of this Rate Schedule. Revenues realized from unauthorized over run penalties will be credited to the Actual Cost Adjustment (ACA) account as recovery of gas costs. C

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

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RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. S

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

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RATE SCHEDULE NO. 307
Balancing, Cash-Out, and Agency Authorization

APPLICABILITY

The provisions of this Rate Schedule 307 shall apply to all tariffed transportation services provided by the Company under Rate Schedules 313 and 314, as well as all transportation special contracts, unless expressly provided otherwise therein.

LIMITATIONS ON INTRA-MONTH IMBALANCES

Receipts and deliveries of gas hereunder shall be at uniform rates of flow with no significant fluctuations or imbalances. Customers (or its Agent) are responsible to match daily gas deliveries into the Company's system with daily gas consumption by Customer as closely as possible. Any imbalances shall be corrected by the Customer (or its Agent), insofar as practicable, during the month in which they occur. Customers (or its Agent) are expected to proactively manage intra-month imbalances. Customer (or its Agent) may adjust its daily nominations during a month in order to correct any accumulated imbalance and maintain a monthly balance subject to the operating limitations of the Company. The Company reserves the right to limit the amount of such imbalances to avoid operating problems, comply with balancing requirements of the upstream pipeline(s), and to mitigate the need to acquire additional daily supply at prices that would adversely affect sales customers. The Customer (or its Agent) will be responsible for any imbalance charges assessed by upstream pipeline(s) in connection with any gas transported by the Customer under this Rate Schedule.

In the event Customer (or its Agent) fails to abide by the requirements set forth above, the Company shall have the right to curtail deliveries to Customer (Customers in a transportation pool operated by a single Agent will be curtailed on a pro rata basis based on nominated quantities) if an imbalance is negative or reducing Customer's nominated quantities if an imbalance is positive. The Customer will be responsible for any imbalance charges assessed by upstream pipeline(s) in connection with any gas transported by the Customer. The Company reserves the right to take other reasonable action to mitigate system operational problems. The Company will use its reasonable efforts to notify the Customer or the Customer's Agent before proceeding with a unilateral nomination reduction or delivery curtailment and will notify Customer of any reduction to Customer's nomination that has been instituted by the Company. The Company reserves the right to initiate Standby Sales Service if elected by the Customer pursuant to Rate Schedule 313 when, in the judgment of the Company, such action is necessary to reduce or eliminate operational problems resulting from the gas imbalances of the Customer. The Company will use reasonable efforts to notify the Customer or the Customers' Agent before initiating Standby Sales Service hereunder. N

By 11:30 am Eastern Time on the fifth business day prior to the beginning of each month, the Customer must inform the Company of the nominating Agent for gas to be transported. If no notification to the contrary is provided, the Agent providing service during the prior month shall be deemed to be the nominating Agent by default. By 11:30 am Eastern Time on the fourth business day prior to the beginning of each month, the Customer shall submit a timely and valid nomination for transportation. Changes to nominations for gas transportation within the month are due by 11:30 am Eastern Time on the business day prior to gas flow. The Company will have no obligation to accommodate "late" or "next day intraday" or "intraday" nomination changes.

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BALANCING ON UPSTREAM PIPELINE(S)

It shall be the Customer's responsibility to remain in balance on a daily and monthly basis with upstream pipeline(s) to avoid any assessment of penalties by such pipeline(s) against the Company. If the Company is assessed a penalty by an upstream pipeline, the Company shall have the right to pass-through all such penalties to the Customer or its Agent if the Customer has had an imbalance with the Company during the period for which the penalty was assessed.

MONTHLY IMBALANCE RESOLUTION

Any differences between the monthly quantities delivered to the Company's city gate facilities for the account of the Customer, and the monthly quantities consumed by the Customer as metered by the Company, shall be the monthly imbalance. The Percentage of Imbalance is defined as the monthly imbalance divided by the monthly quantities consumed by the customer. Unless the Company and Customer agree to correct imbalances "in kind," the imbalance shall be resolved monthly by "cashing out" the imbalances as they are known to exist at that time. If the Customer consumes more gas than it has delivered to the Company, the Customer will be deemed to be "short" by the amount of the deficiency, and the Company will sell the amount of the deficiency to the Customer by charging the price as specified below. If the Customer consumes less gas than has been delivered to the Company, the Customer will be deemed to be "long" by the amount of the surplus, and the Company will buy the amount of the surplus from the Customer by paying the price as specified below.

If Customer's monthly imbalance is less than or equal to 2% of the total monthly volume consumed or if the total aggregated monthly imbalance for the Agent is less than or equal to 2% of the total monthly volume consumed by all of the Agent's Customers in that transportation pool, and such imbalance or aggregated monthly imbalance is long, then the price paid by the Company will be the sum of (a) the average of the weekly "Weighted Index Price" as defined below plus (b) the pipelines Rate Schedule FT variable charges at the applicable pipeline percentages that comprise the "Weighted Index Price," including applicable fuel and surcharges, for delivery to the Company's city gate.

If Customer's monthly imbalance is less than or equal to 2% of the total monthly volume consumed, or if the total aggregated monthly imbalance for the Agent is less than or equal to 2% of the total monthly volume consumed by all of Agent's Customers in that transportation pool, and such imbalance is short, then the price paid by the Customer (or Agent) will be the sum of (a) the average of the weekly "Weighted Index Price" as defined below plus (b) the pipelines Rate Schedule IT charges at the applicable pipeline percentages that comprise the "Weighted Index Price," including applicable fuel and surcharges, for delivery to the Company's city gate.

If the Customer (or Agent) is "short" by more than 2% of the monthly volume consumed, the price paid by the Customer (or Agent) to the Company for each dekatherm of the total deficiency will be equal to the highest "Weighted Index Price" for any week beginning in the calendar month as published in *Natural Gas Week*, plus the pipelines Rate Schedule IT charges at the applicable pipeline percentages that comprise the "Weighted Index Price," including applicable fuel and surcharges, and deliver to the Company's city gate, times the premium percentage corresponding to the percentage of the deficiency listed in the table below.

If the Customer (or Agent) is "long" by more than 2% of the monthly volume consumed, the price paid by the Company to the Customer (or Agent) for each dekatherm of the total surplus will be equal to the lowest "Weighted Index Price" for any week beginning in the calendar month as published in *Natural Gas Week*, plus the pipelines Rate Schedule FT variable charges, including

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applicable fuel and surcharges, at the applicable pipeline percentages that comprise the "Weighted Index Price" and deliver to the Company's city gate, times the premium percentage corresponding to the percentage of the deficiency listed in the table below.

Percentage of the Imbalance	Short (Premium)	Long (Discount)
Over 2% & equal to or less than 5%	110%	90%
Over 5% & equal to or less than 10%	120%	80%
Over 10% & equal to or less than 15%	130%	70%
Over 15% & equal to or less than 20%	140%	60%
Over 20%	150%	50%

The "Weighted Index Price" shall be derived from the prices published in *Natural Gas Week* in the table Natural Gas Weekly Spot Prices for the following pipeline designations and weighted by the corresponding percentages set forth below:

TEXAS (SOUTH/EAST), Tenn Zone 0	X	.3028
+		
GULF COAST, Tenn 500 So LA Z1	X	.3806
+		
GULF COAST, Tenn 800 So LA Z1	X	.3166[1]

If an index listed in the table above fails to publish, the Company will use an average of the published corresponding Gas Daily indexes for the corresponding dates not published in Natural Gas Week. N

The Company will collect gross receipts tax on the incremental gas related charges.

Any difference between the actual cost of gas incurred by the Company and the Index price as defined in the previous paragraph will be accounted for in the Actual Cost Adjustment account in a manner consistent with Rule No. 1220-4-1-12 of the TRA Rules and Regulations. Increments or decrements which may result from the PGA adjustments will not apply to the cash-out of imbalances.

AGENCY AUTHORIZATION FORM

Certain Rate Schedules permit a Customer to appoint a Customer's Agent to act on its behalf with respect to nominations, imbalance resolution, and/or billing. Customer shall authorize a Customer's Agent by executing an Agency Authorization Form in the form attached to this Rate Schedule. In order to be considered a Customer's Agent, a third party must execute and be in compliance with all of the terms of the Customer Agent Agreement form set forth in Appendix A to the Company's Service Regulations. To the extent that the Agent appointed by the Customer is common to other Customers of the Company, the Company will permit such Agent to aggregate all such qualifying Customers' transportation quantities for purposes of administering service to such Agent. Once a Customer has designated an Agent, the Agent is then authorized to act on behalf of that Customer and as such, the Agent will be considered as the Customer in all corresponding references contained within this Rate Schedule. The Customer may not change

[1] These percentages are the ratio of the Company's Tennessee Gas Pipeline contract winter capacity in effect at the time of the Company's most recent general rate case.

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Agents within the calendar month without the permission of the Company, unless the Agent's right to conduct business on the Company's system has been suspended by the Company, in which case, the Customer may act without an Agent or may provide written notice to the Company of the new Customer's Agent designated by the Customer. The Company will provide reasonable notice to Customer in the event of any suspension of Customer's Agent and will provide copies to Customer, on an expeditious basis and by electronic or other means, of any formal notices issued to the Customer's Agent. All Agents must utilize the electronic means made available by the Company in order to submit nominations. The Company may recover from the Agent all costs incurred in providing the Agent access to the electronic bulletin board.

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APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations.

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Balancing, Cash-Out, and Agency Authorization

AGENCY AUTHORIZATION FORM

EFFECTIVE DATE _____

CUSTOMER _____

NAME OF FACILITY _____

ACCOUNT NUMBER (S) _____

AGENT _____

AGENT CONTACT _____

AGENT PHONE # _____

This is to advise Piedmont Natural Gas Company that _____**(Customer)** has authorized _____**(Agent)** to act on its behalf for the following transactions:

_____nominations.
_____imbalance resolution.
_____billing.

of gas for the above listed account(s). Piedmont Natural Gas Company is hereby authorized to deal with the Agent directly, and the **CUSTOMER AND THE AGENT UNDERSTAND THAT THEY ARE RESPONSIBLE, JOINTLY AND SEVERALLY, FOR ANY AMOUNTS DUE PIEDMONT NATURAL GAS COMPANY ARISING UNDER THIS RATE SCHEDULE, PIEDMONT'S TENNESSEE SERVICE REGULATIONS, OR AGENT'S CUSTOMER AGENT AGREEMENT** which are not paid on these accounts. Customer will provide Piedmont Natural Gas Company with a revised "AGENCY AUTHORIZATION FORM" at least five (5) business days prior to the beginning of the month for the accounts designated, unless the Agent's right to conduct business has been suspended by Piedmont Natural Gas Company without prior notice.

M

_____
CUSTOMER AUTHORIZED SIGNATURE

_____
AGENT AUTHORIZED SIGNATURE

Please Print:

AGENT'S NAME_____TITLE _____

PHONE #_____FAX #_____

MAILING ADDRESS
Please submit to: End User Transportation
Piedmont Natural Gas Company
P. O. Box 33068
Charlotte, N.C. 28233

OR

End User Transportation
Fax Number: (704) 364-8320

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RATE SCHEDULE NO. 309
Special Availability Service

AVAILABILITY
Gas service under this rate schedule is available to any TRA Rate Schedule No. 303,304, 313, or 314, Customer when the Company has gas supplies or services that it cannot sell at its established fixed rates where the Company's distribution mains are suitable for supplying the desired service. On such occasions, the opportunity is lost to the Company and its Customers. This Rate Schedule is designed to permit the Company to sell such gas and services at special rates for the purpose of enabling the Company to compete with alternative fuels and services available for use by its Customers.

Gas service under this Rate Schedule is available on a limited term basis to Customers who are connected to the Company's distribution system and would otherwise qualify for commercial and industrial sales or transportation service. Gas service may be provided under this Rate Schedule only in the event that the Company has available supplies or services that cannot competitively be provided under other rate schedules. Service under this Rate Schedule is temporary and the Company has the right to discontinue such service. Gas service under this rate schedule will be curtailed prior to service under any other comparable rate schedule.

In the event a Customer has zero consumption during any billing month, this tariff will not apply and service shall be rendered pursuant to the Company's regular rate schedules for the class of service indicated for the purpose of determining a minimum bill and qualifying provisions.

BASE RATE
The Customer shall pay the Company for all gas supplied or services provided under this schedule at a predetermined rate negotiated prior to delivery for limited term periods up to seven consecutive months.

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this Rate Schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Service Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the above stated net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316.

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Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated base rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use priority as specified by the Federal Energy Regulatory Commission (FERC), impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and the Company's Service Regulations. S

TREATMENT OF NEGOTIATED MARGIN LOSSES

Margin losses under this rate schedule shall be recovered by the Company through the Company's Actual Cost Adjustment (ACA) as provided in the Company's Purchased Gas Adjustment (PGA) Rider (TRA Service Schedule No. 311).

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RATE SCHEDULE NO. 310
Resale Service

AVAILABILITY
Sales for Resale Service is available under this rate schedule to any qualified local distribution company who purchases natural gas for the purpose of reselling same, where the Company's distribution mains are suitable for supplying the desired service.

CHARACTER OF SERVICE
The nature of Service provided by Company to Customer under Rate Schedule 310 is firm sales for resale Service. N

MARGIN RATE

Demand Charge (per therm of billing demand)	$.80000
Commodity Charge (per therm)	$.09000

MONTHLY MINIMUM BILL
The minimum monthly bill shall be the monthly demand charge.

BILLING DEMAND
Demand determinants shall be those agreed to in the contract.

COMMODITY CHARGE
The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises.

SERVICE AGREEMENTS
All customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the customer will be assessed a charge of $20.00.

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ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316. Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee. S

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgement as to the available gas supply, customer's load factor or use pattern, end use priority as specified by the Federal Energy Regulatory Commission (FERC), impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the curtailment provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. S

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

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SERVICE SCHEDULE NO. 311
Purchased Gas Adjustment Rider

I. General Provisions.

A. This Purchased Gas Adjustment (PGA) Rider is intended to permit the Company to recover, in a timely fashion, the total cost of gas purchased for delivery to its customers and to assure that the Company does not over-collect or under-collect Gas Costs from its customers.

B. This Rider is intended to apply to all Gas Costs incurred in connection with the purchase, transportation and/or storage of gas purchased for general system supply, including, but not limited to, natural gas purchased from interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of liquefied natural gas (LNG), liquefied petroleum gas (LPG), substitute, supplemental or synthetic natural gas (SNG), and other hydrocarbons used as feed-stock, other distribution companies and end-users, whether or not the Gas Costs are regulated by the Federal Energy Regulatory Commission and whether or not the provider of the gas, transportation or storage is affiliated with the Company.

C. To the extent practicable, any revision in the PGA shall be filed with the Authority no less than thirty (30) days in advance of the proposed effective date and shall be accompanied by the computations and information required by this Rider. It is recognized, however, that in many instances the Company receives less than 30 days notice from its Suppliers and that other conditions may exist which may prevent the Company from providing 30 days advance notice. Therefore, should circumstances occur where information necessary for the determination of an adjustment under this Rider is not available to the Company so that the thirty (30) days requirement may be met, the Company may, upon good cause shown, be permitted to place such rates into effect with shorter advance notice. T

D. The rates for gas service set forth in all of the Rate Schedules of the Company shall be adjusted pursuant to the terms of the PGA, or any specified portion of the PGA as determined by individual Rate Schedule(s).

E. No provision of this Rider shall supersede any provision of a Special Contract approved by the Authority. T

II. Definitions.

A. "Gas Costs" shall mean the total delivered cost of gas paid or to be paid to Suppliers, including, but not limited to, all commodity/gas charges, demand charges, peaking charges, surcharges, emergency gas purchases, over-run charges, capacity charges, standby charges, gas inventory charges, minimum bill charges, minimum take charges, take-or-pay charges and take-and-pay charges (except as provided below), storage charges, service fees and transportation charges and any other similar charges which are paid by the Company to its gas suppliers in connection with the purchase, storage or transportation of gas for the Company's system supply, including Company use and lost and unaccounted for gas. C

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B. **"Fixed Gas Costs"** shall mean all Gas Costs based on the Company's right to demand gas or transportation on a daily or seasonal peak; but unless otherwise ordered by the Authority, shall not include other charges paid for gas reserve dedication (e.g., reservation fees and gas inventory charges), minimum bill charges, minimum take charges, over-run charges, emergency gas charges, take-or-pay charges or take-and-pay charges (all of which shall be considered commodity costs). T

C. **"Gas Charge Adjustment"** shall mean the per unit amount billed by the Company to its customers solely for Gas Costs. The Gas Charge Adjustment shall be separately stated for firm customers and for non-firm customers.

D. **"Suppliers"** shall mean any person or entity, including affiliates of the Company, who locates, purchases, sells, stores and/or transports natural gas or its equivalent for or on behalf of the Company. Suppliers may include, but not be limited to, interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of LNG, LPG, SNG, and other hydrocarbons used as feed-stock, other distribution companies and end-users.

E. **"Computation Period"** shall mean the twelve (12) month period utilized to compute Gas Costs. Such period shall be the twelve (12) month period ending on the last day of a month which is no more than 62 days prior to the filing date of a PGA.

F. **"Demand Billing Determinants"** shall mean the annualized volumes for which the Company has contracted with Suppliers as of the first day of the Filing Month.

G. **"Commodity Billing Determinants"** shall mean the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. Should the Company expect to purchase commodity gas from several Suppliers, the Company shall allocate to each supplier a percentage of the total metered throughput, regardless of source, during the Computation Period, adjusted for known and measurable changes. The percentage used to allocate among Suppliers shall be based on historical takes during the Computation Period, if appropriate; otherwise it shall be based upon the best estimate of the Company.

H. **"Filing Month"** shall mean the month in which a proposed revision is to become effective.

III. Computation and Application of the PGA.

The PGA shall consist of three major components: (1) the Gas Charge Adjustment; (2) the Refund Adjustment; and (3) the Actual Cost Adjustment (ACA).

A. Computation of Gas Charge Adjustment.

The Company shall compute the jurisdictional Gas Charge Adjustment at such time that the Company determines that there is a significant change in its Gas Costs.

1. **Formulas.** The following formulas shall be used to compute the Gas Charge Adjustment:

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$$Firm\ GCA = \left[\left(\frac{D \pm DACA}{SF}\right) - DB\right] + \left[\left(\frac{P + T + SR \pm CACA}{ST}\right) - CB\right]$$

$$Non\text{-}Firm\ GCA = \left(\frac{P + T + SR \pm CACA}{ST}\right) - CB$$

1. Definitions of Formula Components.

GCA = The Gas Charge Adjustment in dollars per Ccf/Therm, rounded to no more than five decimal places.

D = The sum of all fixed Gas Costs.

DACA = The demand portion of the ACA.

P = The sum of all commodity/gas charges.

T = The sum of all transportation charges.

SR = The sum of all FERC approved surcharges.

CACA = The commodity portion of the ACA.

DB = The per unit rate of demand costs or other fixed charges included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves). T

CB = The per unit rate of variable Gas Costs included in base rates in the most recently completed general rate case (which may be zero if the Company so elects and the Authority so approves). T

SF = Firm sales.

ST = Total sales.

2. Determination of Factors for Gas Charge Adjustment.

a. Demand Charges (Factor D)

All fixed Gas Costs that do not vary with the amount of gas purchased or transported, including, but not limited to, the product resulting from the multiplication of (1) the respective Demand Billing Determinants by (2) the

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demand rates effective the first day of the Filing Month and (3) any fixed storage charges.

b. Demand Actual Cost Adjustment (Factor DACA)

See Subsection C of Section III.

c. Purchased Commodity Charges (Factor P)

All commodity or other variable gas costs associated with the amount of gas purchased or transported including, but not limited to, the product resulting from the multiplication of (1) the respective Commodity Billing Determinants by (2) the respective supplier's commodity/gas rate which are known, or if not known which are reasonably anticipated, to be in effect on the first day of the Filing Month.

d. Transportation Charges (Factor T)

The transportation charges actually invoiced to the Company during the Computation Period or expected to be invoiced to the Company during the current period.

e. FERC Approved Surcharges (Factor SR)

The sum of all FERC approved surcharges, including gas inventory charges or its equivalent, actually invoiced or expected to be invoiced to the Company during the Computation Period or to be effective the first day of the Filing Month by respective Suppliers.

f. Actual Cost Adjustment (Factor ACA)

See Subsection C of Section III.

g. Firm Sales (Factor SF)

Total volumes billed to the Company's firm customers during the Computation Period, regardless of source, adjusted for known and measurable changes.

h. Total Sales (Factor ST)

Total volumes billed to all the Company's customers during the Computation Period, regardless of source, adjusted for known measurable changes.

3. Modification of Formulas.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; therefore, the formulas may be modified for use with such rate schedules. In addition, the formulas may be modified from time to time to carry out the intent of this PGA Rider. Any amendment to the formulas shall be effective on the proposed effective date of the amendment unless the Authority shall act to suspend the proposed amendment within

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thirty days after the filing of the proposed amendment, in which case the proposed amendment shall be subject to notice and hearing.

4. Filing with the Authority. T

The computation of the Gas Charge Adjustment shall be filed in accordance with the notice requirements specified in Subsection C of Section I of this Rider, and shall remain in effect until a revised Gas Charge Adjustment is computed and filed pursuant to this Rider.

The Company shall file with the Authority a transmittal letter, an exhibit showing the computation of the Gas Charge Adjustment, a PGA tariff sheet, and any applicable revised tariff sheets issued by Suppliers. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the primary reasons for revision, and the effective date. T

If the Company proposes to recover any Gas Costs relating to (1) any payments to an affiliate or (2) any payments to a non-affiliate for emergency gas, over-run charges, take-or-pay charges and take-or-pay charges (except as provided below) or (3) the payment of any demand or fixed charges in connection with an increase in contract demand, the Company must file with the Authority a statement setting forth the reasons why such charges were incurred and sufficient information to permit the Authority to determine if such payments were prudently made under the conditions which existed at the time the purchase decisions were made. T

Any filing of a rate change under this Rider shall be effective on the proposed effective date unless the Authority shall act to suspend the proposed change within thirty day after the filing, in which case the filing shall be subject to notice and hearing. T

The recovery of pipeline take-or-pay charges which were the subject of Docket No. U-87-7590 shall continue to be handled under procedures approved by the Authority in that docket until such time as such procedures may be modified or amended by further order of the Authority. T

B. Refund Adjustment.

The Refund Adjustment shall be separately stated for firm and non-firm customers, and may be either positive or negative.

1. Computation of Refund Adjustment.

The Company shall compute a Refund Adjustment on the last day of each calendar quarter using the following formulas:

$$Firm\ RA = \left(\frac{DR1 - DR2}{SFR}\right) + \left(\frac{CR1 - CR2 \pm CR3 \pm i}{STR}\right)$$

$$Non\text{-}Firm\ RA = \left(\frac{CR1 - CR2 \pm CR3 \pm i}{STR}\right)$$

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2. Definitions of Formula Components.

RA = The Refund Adjustment in dollars per Ccf/therm, rounded to no more than five decimal places.

DR1 = Demand refund not included in a currently effective Refund Adjustment, and received from Suppliers by check, wire transfer, or credit memo.

DR2 = A demand surcharge from a Supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.

CR1 = Commodity refund not included in a currently effective Refund Adjustment, and received from Suppliers by check, wire transfer, or credit memo.

CR2 = A commodity surcharge from a supplier not includable in the Gas Charge Adjustment, and not included in a currently effective Refund Adjustment.

CR3 = The residual balance of an expired Refund Adjustment.

I = Interest on the "Refund Due Customers' Account," using the average monthly balance based on the beginning and ending monthly balances. The interest rates for each calendar quarter used to compute such interest shall be a rate 2% below the arithmetic mean (to the nearest one-hundredth of one percent) of the prime rate value published in the "Federal Reserve Bulletin" or in the Federal Reserve's "Selected Interest Rates" for the 4th, 3rd, and 2nd months preceding the lst month of the calendar quarter C

SFR = Firm sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.

STR = Total sales as defined in the Gas Charge Adjustment computation, less sales under a transportation or negotiated rate schedule.

3. Modification of Formula.

The formulas set forth above are not designed for use with two-part demand/commodity rate schedules; therefore, the formulas may be modified for use with such rate schedules. In addition, the formulas may be modified from time to time to carry out the intent of this PGA Rider. Any amendment to the formulas shall be effective on the proposed effective date of the amendment unless the Authority shall act to suspend the proposed amendment within thirty days after the filing of the proposed amendment, in which case the proposed amendment shall be subject to notice and hearing. T

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4. **Filing with the Authority.** T

The computation of the Refund Adjustment shall be filed in accordance with the notice requirements specified in Subsection C of Section I this Rider, and shall remain in effect for a period of twelve (12) months or for such longer or shorter period of time as required to appropriately refund the applicable refund amount.

The Company shall file with the Authority a transmittal letter, exhibits showing the computation of the Refund Adjustment and interest calculations, and a PGA tariff sheet. The transmittal letter shall state the PGA tariff sheet number, the service area(s), the reason for adjustment, and the effective date. Should the Company have a Gas Charge Adjustment filing to become effective the same date as a Refund Adjustment, a separate transmittal letter and PGA tariff sheet shall not be necessary. T

C. **Actual Cost Adjustment.**

Commencing with the initial effective date of this Rider, the Company shall calculate the ACA monthly. The Company may, at its option, file monthly to include the ACA in its calculation of the Gas Charge Adjustment but shall be required to do so at least annually. The ACA shall be the difference between (1) revenues billed customers by means of the Gas Charge Adjustment and (2) the cost of gas invoiced the Company by Suppliers plus margin loss (if allowed by order of the Authority in another docket) as reflected in the Deferred Gas Cost account. The balance of said account shall be adjusted for interest at the rate provided for the calculation of interest with respect to the Refund Adjustment. The ACA shall be segregated into demand and commodity, and shall be added to or deducted from, as appropriate, the respective demand and commodity costs included in the Gas Charge Adjustment. Supplemental sheets showing the calculations of margin losses and cost savings shall also be provided. T

D. **Adjustments to Prior Period ACAs.**

In the event that circumstances warrant a correction to or restatement of a prior period ACA, such correction or restatement shall be made in accordance with the ACA calculation in effect for the time period(s) to which the correction or restatement relates. The resulting adjustment shall then be added to or deducted from the appropriate ACA in the next ensuing ACA filing with the Authority. T

E. **Annual Filing with the Authority.** T

Each year, the Company shall file with the Authority an annual report reflecting the transactions in the Deferred Gas Cost Account. Unless the Authority provides written notification to the Company within 180 days, the Deferred Gas Cost Adjustment Account shall be deemed in compliance with the provisions of this Rider.

IV. **Gas Cost Accounting.**

To appropriately match revenues with cost of purchased gas as contemplated under this rule, the Company shall originally record the cost of purchased gas in a "Deferred Gas Cost" account. Monthly, the Company

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shall debit "Natural Gas Purchases" with an amount equal to any gas cost component included in the Company's base tariff rates (base rate) plus the PGA rate, as calculated hereunder, multiplied by the appropriate sales volumes billed to customers. The corresponding monthly credit entry shall be made to the "Deferred Gas Cost" account.

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SERVICE SCHEDULE NO. 312
Equal Payment Plan (EPP)

AVAILABILITY

The Equal Payment Plan ("EPP" or "Plan") is available to customers receiving service under Rate Schedules 301 and 302 whose accounts are in good standing. Good standing shall be defined as not having been removed from the Plan within the last twelve (12) months for non-payment of bills. The Plan is designed to provide the customer the option of paying equal payments over a twelve-month period and is available during any month of the year. Under circumstances where a customer has a difficult time paying his monthly bills, EPP may be used to catch up the past due balance. The customer will be asked to pay as much of the old balance as possible to help keep future payments as low as possible. N

GENERAL TERMS AND CONDITIONS

At the customer's election, the Company will calculate payments under the Plan based on the customer's actual consumption history during the past 12-months adjusted for normal weather. The estimated monthly usage will be priced at the Company's currently approved margin rates plus an estimated purchased gas adjustment factor based on the forward-looking NYMEX futures prices for upcoming 12-month period. Applicable franchise fees and sales tax are then added to arrive at the estimated annual billing amount. If the customer has an outstanding balance, it will be added to the estimated annual amount. The monthly payment will be calculated by dividing the estimated annual billing amount by twelve. After 11 payments have been made, the customer will be sent a twelfth-month "true-up" bill reflecting any underage or overage of the total of the past 11 payments. Underages will be treated as debits and overages will be treated as credits and applied to the next billing. Refunds may be made by check if the overage exceeds $25.00. Unless otherwise requested, the customer will remain on EPP after the twelfth bill with a new monthly EPP amount calculated.

MID-YEAR ADJUSTMENTS

In order to avoid unusually large debit or credit balances to the customer's account, the Company may make mid-year adjustments to the EPP payments. During periods of highly volatile wholesale gas prices, more frequent EPP adjustments may be required to avoid unusually large debit or credit balances. The Company will notify the customer with a notation on the bill, bill insert or separate mailing of any adjustments to payments.

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RATE SCHEDULE NO. 313
Firm Transportation Service

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer whose average daily gas usage is reasonably anticipated to equal or exceed 500 therms per day. All Service under this Rate Schedule shall be contingent upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations. Upon commencement of Service under this Rate Schedule, any reclassification or change in quantity or character of Service to Customer shall be subject to the provisions of this Rate Schedule 313 and the procedures set forth in the Company's Service Regulations. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. N

CHARACTER OF SERVICE

The nature of service provided by Company to Customer under this Rate Schedule is firm transportation Service. N

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 309 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may, subject to the consent of the Company, elect to discontinue service under this Rate Schedule and receive service under Rate Schedule 303 by giving written notice to the Company prior to March 1 of any year. The Company will not withhold such consent provided (a) the Company continues to offer Large General Sales Service under Rate Schedule 303, (b) the Company is able to provide Service under Rate Schedule 303 under commercially reasonable terms and conditions, and (c) the analyses applicable to reclassifications or changes in Service set forth in the Company's Service Regulations support such consent. If timely notice is received from Customer and consent is provided by Company, the Customer shall discontinue service under this Rate Schedule and Company shall provide Service under Rate Schedule 303 effective the first June 1 following the notice. N

All gas delivered to pursuant to this Rate Schedule shall be metered by the Company separately from any gas delivered to Customer under any of the Company's other Rate Schedules. N

The Company will redeliver gas received by Company from upstream pipeline(s) for the Customer's account under this Rate Schedule in accordance with the Customer's scheduled and confirmed nominations and subject to the Company's Operating Conditions. N

APPLICABILITY

Transportation service is available under this Rate Schedule to any qualified Customer connected to the Company's system who has obtained an independent supply of natural gas and has arranged to have this supply delivered to one of the Company's existing delivery points for transportation by the Company to the Customer's facilities.

The Company will deliver gas previously transported by a connected pipeline for the Customer's account under this Rate Schedule on a day-to-day basis in accordance with the

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Customer's scheduled and confirmed nominations, subject to such maximum allowable daily deliveries as may be specified in the Gas Service Contract. The Company reserves the right to suspend service on any day when, in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. The Company reserves the right to limit, allocate, or direct third party gas nominations among the interstate pipelines serving the Company's distribution system, when, in the Company's sole opinion, such action is necessary to maintain the operational integrity of the system. D

STANDBY SALES SERVICE

At the option of the Customer, an election may be made monthly to receive Standby Sales Service from the Company under this Rate Schedule for delivery to the Customer at the Company's city gate. The Customer will also receive Standby Sales Service as a default if the Customer or the Customer's agent fails to submit a timely and valid nomination for transportation service. In addition to paying the Monthly Standby Index Price set forth below for Standby Sales Service hereunder, the Customer will utilize the transportation services and incur the charges otherwise applicable under this Rate Schedule to cause such gas supplies to be delivered to the Customer's meter. The price which the Customer shall pay for the gas supplied under this paragraph will be the Monthly Standby Index Price defined as follows: "The weighted average index price for the applicable month as published in the first *Natural Gas Week* for such month in the table Natural Gas Weekly Spot Prices ,for:

TEXAS (SOUTH/EAST), Tenn Zone 1 Zone 0:South Texas		X	.3028
	+		
GULF COAST, Tenn 500 So La Z1 Louisiana		X	.3806
	+		
GULF COAST, Tenn 800 So La Z1		X	.3166

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If the Customer nominates transportation service hereunder and purchases gas supplies from a third party supplier, and such Customer's consumption exceeds actual deliveries to the Company from such third party supplier to the point where operational problems are created for the Company, then the Company shall have the right, at it sole discretion, to initiate Standby Sales Service to the Customer. The price for such service shall be the same as set forth above except when the Company is required by such imbalance shortfall to purchase incremental volumes of gas supplies. In this case the Customer receiving Standby Sales Service will pay the higher of (on a daily basis) the Monthly Standby Index Price or the Daily Standby Index Price defined as follows:

The midpoint daily index price as published in Gas Daily for the day of consumption as stated in the "Daily Price Survey," for the "Tennessee 500 Leg." For days of consumption when the Gas Daily is not published, the Gas Daily price shall equal the price as published on the nearest subsequent day by Gas Daily.

Applicable firm transportation tariff commodity charges, fuel and any other surcharges as defined in the above transporters' FERC approved tariffs will be added to the above standby index prices. The Company will collect gross receipts tax on the incremental gas related charges.

Any difference between the actual cost of gas incurred by the Company and the Index price as defined in the previous paragraph will be accounted for in the Actual Cost Adjustment account in a manner consistent with Rule No. 1220-4-1-12 of the TRA Rules and Regulations. Increments or decrements which may result from the PGA adjustments will not apply to the standby index prices.

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MARGIN RATE

Monthly Charge	$800.00	I
Demand Charge (per therm of billing demand)	$.80000	
Commodity Charge (per therm)		R
1st Step (0-15,000 therms)	$.09682	
2nd Step (15,001-40,000 therms)	$.08953	
3rd Step (40,001-90,000 therms)	$.06450	
4th Step (Over 90,000 therms)	$.02764	

MONTHLY MINIMUM BILL

The minimum monthly bill shall be the Monthly Charge plus the Demand Charge multiplied by the billing demand determined as described below. T

MONTHLY CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. N

BILLING DEMAND

The billing demand shall be determined as follows:

Customer billing demand determinate shall be the highest daily usage during the period from November 1 to March 31 of the previous winter period as metered and reported to the Company by the telemetering equipment installed by the Company. Changes to the Customer's billing demand determinate will become effective June 1 of each year. The per unit charge may be adjusted from time to time to reflect rate changes, including, but not limited to, a general change in system rates or a change in pipeline capacity charges billed to the Company.

For Customers commencing initial gas service under this Rate Schedule and who do not have a consumption history from other services provided by the Company, the billing demand determinate shall be based upon a reasonable assumption of usage considering the connected load. If a Customer has received gas service from the Company prior to receiving service under this Rate Schedule but does not have daily telemetered records to determine peak day usage as described above, the Company shall determine a billing demand based on the greater of: 1) the month of highest consumption for the period to date multiplied by six percent (6%), or 2) 500 therms.

COMMODITY CHARGE

The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

SERVICE AGREEMENTS

All Customers receiving service under this Rate Schedule shall be required to execute the Company's standard contracts and/or service applications and shall be subject to the Company's Rules and Regulations as filed with and approved by the Tennessee Regulatory Authority (TRA).

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PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for transportation service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with the Rules, Regulations and Orders of the TRA and the Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, the TRA Rules and Regulations, Orders of the TRA, and the Laws of the State of Tennessee. N

SERVICE CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. S

BALANCING, CASH-OUT, AND AGENCY AUTHORIZATION
Service under this Rate Schedule shall be subject to all of the provisions and requirements of Rate Schedule 307, "Balancing, Cash-Out, and Agency Authorization." N

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS
The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

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RATE SCHEDULE NO. 314
INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee **ON AN INTERRUPTIBLE BASIS** to any full requirements non-residential Customer whose average daily gas usage is reasonably anticipated to equal or exceed 500 therms per day. All Service under this Rate Schedule shall be contingent upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations. Upon commencement of Service under this Rate Schedule, any reclassification or change in quantity or character of Service to Customer shall be subject to the provisions of this Rate Schedule 314 and the procedures set forth in the Company's Service Regulations. Service under this Rate Schedule is contingent upon the installation by the Company of telemetering equipment that reports daily consumption. N

CHARACTER OF SERVICE

The nature of Service provided by Company to Customer under this Rate Schedule is interruptible transportation service. N

Once a qualified Customer elects service under this Rate Schedule, all services will be provided under the terms and conditions of this Rate Schedule for a term extending through the following May 31. Upon meeting the qualifications contained therein, a Customer may receive service under Rate Schedule 309 concurrent with service provided under this Rate Schedule. Subject to the requirements set forth above, a Customer may, subject to the consent of the Company, elect to discontinue service under this Rate Schedule and receive service under Rate Schedule 304 and/or 310 by giving written notice to the Company prior to April 1 of any year. The Company will not withhold such consent provided (a) the Company continues to offer Interruptible General Sales Service under Rate Schedule 304, (b) the Company is able to provide Service under Rate Schedule 304 under commercially reasonable terms and conditions, and (c) the analyses applicable to reclassifications or changes in Service set forth in the Company's Service Regulations support such consent. If timely notice is received from Customer and consent is provided by Company, the Customer shall discontinue service under this Rate Schedule and Company shall provide Service under Rate Schedule 304/310, as applicable, effective the first June 1 following the notice. N

All gas delivered to pursuant to this Rate Schedule shall be metered by the Company separately from any gas delivered to Customer under any of the Company's other Rate Schedules. N

The Company will redeliver gas received by Company from upstream pipeline(s) for the Customer's account under this Rate Schedule in accordance with the Customer's scheduled and confirmed nominations and subject to the Company's Operating Conditions. N

Customers receiving services under this Rate Schedule shall maintain, in useable condition, alternate-fuel facilities with ample on-site alternate fuel capability for supplying 100% of the establishment's gas requirements during periods of gas interruption or curtailment. Such interruption or curtailment shall be immediately effective upon verbal or written notification by the Company, and Customer shall refrain from using gas until permitted to do so by the Company. It is understood and agreed that the Company will have the right to suspend gas service without further notice to the Customer in the event Customer fails to curtail Customer's use of gas in accordance with the Company's notice of curtailment.

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APPLICABILITY

Transportation service is available under this Rate Schedule to any qualified Customer connected to the Company's system who has obtained an independent supply of natural gas and has arranged to have this supply delivered to one of the Company's existing delivery points for transportation by the Company to the Customer's facilities.

The Company will deliver **ON AN INTERRUPTIBLE BASIS** gas previously transported by a connected pipeline for the Customer's account under this Rate Schedule on a day-to-day basis in accordance with the Customer's scheduled and confirmed nominations. The Company reserves the right to suspend service on any day when, in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. The Company reserves the right to limit, allocate, or direct third party gas nominations among the interstate pipelines serving the Company's distribution system, when, in the Company's sole opinion, such action is necessary to maintain the operational integrity of the system. D

MARGIN RATE

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Monthly Charge	$800.00
Commodity Charge (per therm)	
1st Step (0-15,000 therms)	$.09682
2nd Step (15,001-40,000 therms)	$.08953
3rd Step (40,001-90,000 therms)	$.06450
4th Step (Over 90,000 therms)	$.02764

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MONTHLY MINIMUM BILL

The minimum monthly bill shall be the Monthly Charge. T

MONTHLY CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. N

COMMODITY CHARGE

The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

SERVICE AGREEMENTS

All Customers receiving service pursuant to this Rate Schedule shall be required to execute the Company's standard contracts and/or service applications and shall be subject to the Company's Rules and Regulations as filed with and approved by the Tennessee Regulatory Authority (TRA).

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

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ADJUSTMENTS

Bills for transportation service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations.

Purchase gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with the Rules, Regulations and Orders of the TRA and the Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new or additional service or the transfer of existing service to a higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, the TRA Rules and Regulations, the Orders of the TRA, and the Laws of the State of Tennessee. N

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is interruptible and is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. S

BALANCING, CASH-OUT, AND AGENCY AUTHORIZATION

Service under this Rate Schedule shall be subject to all of the provisions and requirements of Rate Schedule 307, "Balancing, Cash-Out, and Agency Authorization." N

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

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SERVICE SCHEDULE NO. 315
Weather Normalization Adjustment (WNA) Rider

I. Provision for Adjustment

The base rates per therm (100,000 Btu) for gas service set forth in any rate schedules utilized by the Authority in determining normalized test period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment".

The Weather Normalization Adjustment will be applicable for bills rendered on and after October 1 and continuing through the final billing cycle in April of each year. C

II. Definitions

For the purposes of this Rider:

"Authority" means the Tennessee Regulatory Authority.

"Relevant Rate Order" means the final order of the Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Authority specifically prescribing or fixing the factors and procedures to be used in the application of this Rider.

III. Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment shall be computed to the nearest one-hundredth cent per therm by the following formula:

$$WNA_i = R_i * \frac{(HSF_i(NDD-ADD))}{(BL_i + (HSF_i \times ADD))}$$

Where:

I = any particular rate schedule or billing classification within any particular rate schedule that contains more than one billing classification.

WNA_i = Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per therm.

R_i = weighted average base rate (base rate less any embedded gas cost) of temperature sensitive sales for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

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HSF_i = heat sensitive factor for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

NDD = normal billing cycle heating degree days utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

ADD = actual billing cycle heating degree days.

BL_i = base load sales for the i^{th} schedule or classification utilized by the Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues.

IV. Filing with Authority

The Company will file as directed by the Authority (a) a copy of each computation of the Weather Normalization Adjustment, (b) a schedule showing the effective date of each such Weather Normalization Adjustment, and a schedule showing the factors or values derived from the Relevant Rate Order used in calculating such Weather Normalization Adjustment.

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SERVICE SCHEDULE NO. 316
Performance Incentive Plan

Applicability

The Performance Incentive Plan (the Plan) replaces the annual reasonableness or prudence review of the Company's gas purchasing activities overseen by the Tennessee Regulatory Authority (Authority or TRA). The Plan does not preclude the Authority from conducting an independent investigation into or examination of any aspect of the Plan or the Company's conduct thereunder. The Plan is designed to provide incentives to the Company in a manner that will produce rewards for its customers and its stockholders and improvements in the Company's gas procurement and capacity management activities. Each plan year (Plan Year) will begin July 1st. The annual provisions and filings herein would apply to this annual period. The Plan will continue until the Plan is either (a) terminated at the end of a Plan Year by not less than 90 days notice by the Company to the Authority or (b) the Plan is modified, amended or terminated by the Authority on a prospective basis.

Overview of Structure

The Plan establishes a predefined benchmark index to which the Company's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees and the treatment of off-system sales and wholesale interstate sale for resale transactions. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 75%-customers / 25%- stockholders basis for the Plan Year commencing on July 1, 2006.

The Plan also is designed to encourage the Company to actively market off-peak unutilized transportation and storage capacity on pipelines in the secondary market. It also addresses the sharing of asset management fees paid by asset managers, and other forms of compensation received by the Company for the release and/or utilization of the Company's transportation and storage assets by third-parties. The Company shall notify the TRA Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan. The net incentive benefits or costs of such activities will be shared between the Company's customers and the Company utilizing a 75%-customers / 25%-stockholders formula commencing on July 1, 2006.

Every three years the Company's activities under the Plan will be reviewed comprehensively by an independent consultant. The first triennial review shall occur in the autumn of 2008. The scope of the review may include all transactions and activities related to the Performance Incentive Plan, including, but not limited to, natural gas procurement, capacity management, storage, hedging, reserve margins, and off-system sales.

The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually. In connection with the Performance Incentive Plan, the Company shall file with the Authority Staff,

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and supply a copy to the Consumer Advocate and Protection Division of the Tennessee Attorney General (CAD), and update each year, a Three Year Supply Plan. The Company will negotiate/obtain firm capacity, interruptible capacity and/or gas supply pursuant to such plan. C

Commodity Costs

Each month the Company will compare its *total city gate commodity and cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as:

$$I = F_f(P_0K_{0+P_1K_1}+P_cK_c+...P_\alpha K_\alpha) +F_0O+F_dD; \text{ where}$$
$$F_r+F_0+F_d =1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under the Company's FT, negotiated FT, and IT service agreements. C

P = the Inside FERC Gas Market Report price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gulf Transmission (CGT) - mainline, and subscript α denotes new incremental firm services to which the Company may subscribe in the future.[2] The indices used for calculating Midwestern capacity shall be those produced by Natural Gas Intelligence for monthly purchases and Gas Daily for daily purchases. The commodity index prices will be adjusted to include the appropriate pipeline firm transportation (FT) and interruptible transportation (IT) commodity transportation charges and fuel retention to the city gate under the Company's FT, negotiated FT, and IT service agreements.[3] C

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[1] Gas purchases associated with service provided under Texas Eastern Transmission Company Rate Schedule SCT shall be excluded from the incentive mechanism. The Company will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, the Plan will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, the Company will exclude any commodity costs incurred downstream of the city gate to storage so that the Company's actual costs and the benchmark index are calculated on the same basis.

[2] To the extent that the Company renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, the Company shall modify the monthly commodity price index to reflect such discount.

[3] Capacity released for a month shall be excluded from the benchmark calculation for that month, excluding capacity released under an agreement where the Company maintains city gate delivery rights for the released capacity during such month.

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K = the fraction (relative to total maximum daily contract entitlement) of the Company's total firm, negotiated firm, and interruptible transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[4] C

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to the Company's system using transportation arrangements other than the Company's FT, negotiated FT, and IT contracts. C

0 = the weighted average of Inside FERC Gas Market Report first-of-the-month price indices, plus applicable IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by the Company and delivered to the Company's system using transportation arrangements other than the Company's FT, negotiated FT, and IT contracts. C

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from Gas Daily for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate transportation commodity charges and fuel retention to the city gate.

Gas Supply Reservation Fees

The Company will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan Year, the Company will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using the Company's firm, negotiated firm, and interruptible transportation and capacity entitlements (the costs of which are recovered from the Company's ratepayers) shall be credited to the Plan and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by the Company in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, the Company will impute such costs for its related C
supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between the Company's

[4] Because the aggregate maximum daily contract quantities in the Company's FT contract portfolio vary by month over the course of the year, the weights will be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, will also vary as the Company renegotiates existing or adds new FT contracts. As new contracts are negotiated, the Company shall modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements. Citygate benchmark calculations shall be computed utilizing the Company's Design Day delivery requirements (deliveries required on a peak day).

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actual costs and such index price is taken into account under the Plan. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared with customers on a 75%- customer / 25%-stockholders basis.

Capacity Management

To the extent the Company is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings and/or asset management fees, or other forms of compensation associated with such activities, shall be shared by the Company and customers according to the following sharing formula: 75%-customers / 25%-stockholders. The Company shall notify the TRA Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan.

Hedging Activities

The Company may engage in hedging transactions[5] within the PGA/ACA mechanism. Costs related to hedging transactions may be recovered through the ACA account; provided, however, that such costs recovered through the ACA account shall not exceed one percent (1%) of total annual gas costs.[6] Costs related to hedging transactions recoverable through the ACA account shall be defined as all direct, transaction related costs arising from the Company's prudent efforts to stabilize or hedge its commodity gas costs including, without limitation, brokerage fees, and the costs of financial instruments.

All costs related to hedging transactions, in addition to all gains and losses from hedging transactions, shall be credited/debited to the ACA account in the respective month that each hedging transaction closes. Costs related to hedging transactions that are incurred prior to the month that the hedging transaction closes shall be temporarily recorded in a separate, non-interest bearing account for tracking purposes.

Determination of Shared Saving

Each month during the term of the Plan, the Company will compute any gains or losses in accordance with the Plan. If the Company earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If the Company incurs a loss, that same IPA will be credited with such loss. During a Plan Year, the Company will be limited to overall gains or losses totaling $1.6 million. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in the Company's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, the Company may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire Plan Year are available.

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[5] Hedging transactions, as used herein, shall include but not be limited to futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs.

[6] One percent (1%) of total annual gas costs, for the purposes of establishing a recovery cap, shall be computed from the most current audited and approved gas costs for the Company in a TRA docket as of the first day of the month, 12 months prior to the first day of the period under audit.

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Gains or losses accruing to the Company under the Plan will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period. The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually.

Each year, effective November 1, the rates for all customers, excluding transportation customers who receive no direct benefit from any gas cost reductions resulting from the Plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism. Subject to approval by the TRA, the Company may also propose to refund positive IPA balances on an intra-year basis by making direct bill credits to all customers (except transportation customers) where such direct bill credit would be beneficial to customers.

Filing with the Authority

The Company will file calculations of shared savings and shared costs quarterly with the Authority not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each Plan Year. Unless the Authority provides written notification to the Company within 180 days of the annual reports, the Incentive Plan Account shall be deemed in compliance with the provisions of this Service Schedule. The Authority Staff may expand the time for consideration of the annual reports by up to an additional sixty (60) days upon written notification to the Company or longer by mutual agreement or upon a showing of good cause.

Periodic Index Revisions

Because of changes in the natural gas marketplace, the price indices utilized by the Company, and the composition of the Company's purchased gas portfolio may change. The Company shall, within sixty (60) days of identifying a change to a significant component of the mechanism, provide notice of such change to the Authority. Unless the Authority provides written justification to the Company within sixty (60) days of such notice, the price indices shall be deemed approved as proposed by the Company.

Gas Supply Incentive Compensation Program

The Company has in place a Gas Supply Incentive Compensation Program (the Program) designed to provide incentive compensation to selected Gas Supply non-executive employees involved in the implementation of the Company's Incentive Plan and Secondary Marketing Programs in a manner consistent with the benefits achieved for customers and shareholders through improvements in gas procurement and secondary marketing activities. Participants in

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the program receive incentive compensation as recognition for their contribution to the customers and shareholders of the Company through lower gas costs and gains related thereto. Performance measures are established for the Program each year.

During the time this tariff is in effect, the Company will continue to have in place the Gas Supply Incentive Compensation Program, as detailed to the Authority, as it relates to the Company's Incentive Plan. The Company will advise the Authority in writing of any changes to the Program, and unless the Company is advised within 60 days, said changes will become effective. The Authority may expand the time for consideration of such changes upon written notification to the Company. No filing for prior approval is required for changes in the performance measures.

Triennial Review

A comprehensive review of the transactions and activities related to the Performance Incentive Plan shall be conducted by an independent consultant once every three years. The initial triennial review shall be conducted in the autumn of 2008 and subsequent triennial reviews shall be conducted every third year thereafter. The TRA Staff, the CAD, and the Company shall make an effort to maintain a list of no less than five (5) mutually agreeable independent consultants or consulting firms qualified to conduct the aforementioned review. Any dispute concerning whether an independent consultant shall be added to the list shall be resolved by the TRA Staff, after consultation with the Company and the CAD. For each review, the TRA Staff shall select three (3) prospective independent consultants from that list. Each such consultant shall possess the expertise necessary to conduct the review. The TRA Staff shall provide the list of prospective independent consultants to the Company and the CAD via e-mail. The Company and the CAD shall have the right, but not the obligation, to strike one (1) of the prospective independent consultants from the list by identifying the stricken consultant in writing to the TRA Staff within thirty (30) days from the date the list is e-mailed. The TRA Staff shall select the independent consultant from those remaining on the list after the Company's and the CAD's rights to strike have expired. The cost of the review shall be reasonable in relation to its scope. Any and all relationships between the independent consultant and the Company, the TRA Staff, and/or the CAD shall be disclosed, and the independent consultant shall have had no prior relationship with either the Company, the TRA Staff, or the CAD for at least the preceding five (5) years unless the Company, the TRA Staff and the CAD agree in writing to waive this requirement. The TRA Staff, the CAD and the Company may consult amongst themselves during the selection process; provided, however, that all such communications between the parties shall be disclosed to any party not involved in such communication so that each party may participate fully in the selection process.

The scope of the triennial reviews may include all transactions and activities related either directly or indirectly to the Performance Incentive Plan as conducted by the Company or its affiliates, including, but not limited to, the following areas of transactions and activities: (a) natural gas procurement; (b) capacity management; (c) storage; (d) hedging; (e) reserve margins; and (f) off-system sales. The scope of each triennial review shall include a review of each of the foregoing matters as well as such additional matters as may be reasonably identified by the

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Company, the TRA Staff, or the CAD relative to the operation or results of the Performance Incentive Plan.

The Company, the TRA Staff, or the CAD may present documents and information to the independent consultant for the independent consultant's review and consideration. Copies of all such documents and information shall be presented simultaneously to the independent consultant and all other parties.

The independent consultant shall make findings of fact, as well as identify and describe areas of concern and improvement, if any, that in the consultant's opinion warrant further consideration; however, the independent consultant shall not propose changes to the structure of the Performance Incentive Plan itself. The independent consultant shall complete and issue a written report of its findings and conclusions by July 1 of the year immediately following the triennial review. The report deadline may be waived by the written consent of the TRA Staff, the Company, and the CAD.

The independent consultant shall not propose changes to the structure of the Performance Incentive Plan itself; however, the TRA Staff, the Company, or the CAD may use the report of the independent consultant as grounds for making recommendations or proposed changes to the Authority, and the TRA Staff, the Company, or the CAD may support or oppose such recommendations or proposed changes. Any proposed changes to the structure of the Performance Incentive Plan resulting from the initial triennial review or subsequent triennial reviews, whether adopted by agreement or pursuant to a ruling of the Authority, shall be implemented on a prospective basis only beginning with the incentive Plan Year immediately following such agreement or ruling.

The cost of the triennial reviews shall be paid initially by the Company and recovered through the ACA account. The TRA Staff may continue its annual audits of the IPA and the ACA account, and the triennial reviews shall not in any way limit the scope of such annual audits. The CAD retains all of its statutory rights, and the triennial reviews shall not in any way affect such rights.

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RATE SCHEDULE NO. 321
Residential Service-Standard Rate

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered where the Company's distribution mains are suitable for supplying the desired service.

Rate Schedule 321 applies to all residential customers whose base load usage in both of the cycle billing months of July and August is less than 15 therms. Base load usage will be based upon Customer's usage in the Company's most recent residential base load period adjusted for cycle length. Availability of this Rate Schedule for new Customers will be based on reasonably anticipated base load usage. Reclassification of customers between rate schedules will be based upon procedures set forth in the Company's Service Regulations as approved by the Tennessee Regulatory Authority.

MARGIN RATE	Winter (November-March)	Summer (April-October)
Customer Charge (per month)	$13.00	$10.00
Commodity Charge (per therm)	$.32000	$.27000

D

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer charge will be billed from the date of initial service until service is terminated at the Customer's request

BACKUP SERVICE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

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Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Service Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

D

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service".

WEATHER NORMALIZATION ADJUSTMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider".

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RATE SCHEDULE NO. 332
Small General Service – Value Rate

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer whose average daily usage is less than 20 dekatherms per day and whose Summer Load Percentage (SLP) is greater than 30%. Average daily gas usage will be based on the Customer's usage during the most recent calendar year ended on December 31 and adjusted for cycle length. SLP will be determined based upon the percentage of the Customer's total annual usage represented by the Customer's seven (7) month summer usage (April – October). Availability of this Rate Schedule for new Customers or for Customers without at least one full year of usage history will be based on reasonably anticipated usage .

Reclassification of customers between rate schedules will be based upon procedures set forth in the Company's Service Regulations as approved by the Tennessee Regulatory Authority.

MARGIN RATE	**Winter (November-March)**	**Summer (April-October)**
Customer Charge (per month)	$29.00	$29.00
Commodity Charge (per therm)		
1st 2,000 therms	$.35400	$.30300
Over 2,000 therms	$.35400	$.30300

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer charge will be billed from the date of initial service until service is terminated at the Customer's request.

BACKUP RATE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. . The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

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Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard
contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No.306, "Schedule for Limiting and Curtailing Service".

WEATHER NORMALIZATION ADJUSTMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider".

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RATE SCHEDULE NO. 342
Natural Gas Vehicle Fuel

APPLICABILITY AND CHARACTER OF SERVICE

Gas Service under this Rate Schedule is available to any Customer in the area served by the Company in the State of Tennessee for the consumption of natural gas as a motor fuel, upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations.

Gas Service under this Rate Schedule shall be metered at the Customer's Premises, or at the Company's Premises for purposes of providing public access to compressed natural gas filling stations. All gas delivered pursuant to this Rate Schedule shall be metered separately from any gas delivered under any of the Company's other Rate Schedules.

CHARACTER OF SERVICE

The nature of Service provided by Company to Customer under this Rate Schedule is firm sales Service.

N

MARGIN RATE	Winter (November-March)	Summer (April-October)
Monthly Charge	$40.00	$40.00
Rate/therm	$.23109	$.23109
Rate/GGE	$.29117	$.29117

HIGHWAY USE TAXES

The rates to be charged for gas Service pursuant to this Rate Schedule do not include applicable Federal, State and/or local highway motor fuel use taxes and fees. If applicable, bills rendered under this Rate Schedule will include such taxes and fees.

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Service Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

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RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be supplied based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use priority as specified by the Federal Energy Regulatory Commission (FERC), impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT
Gas Service under this Rate Schedule is subject to the provisions contained within Rate Schedule 306, "Schedule for Limiting and Curtailing Service" and the Company's Service Regulations.

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS
The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations.

RIDER
Service to Customers under this Rate Schedule using Company owned and maintained compressor facilities shall be billed at a maximum rate of $0.50 per therm, in addition to the base rate for Service under this Rate Schedule 342 as set forth above.

N

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RATE SCHEDULE NO. 352
Medium General Service

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer, upon application to and consent by the Company to such Service, as provided in the Company's Service Regulations, whose average daily usage is equal to or greater than 20 dekatherms per day but less than 50 dekatherms per day Average daily gas usage will be based on the Customer's usage during the most recent calendar year ended on December 31 and adjusted for cycle length. Availability of this Rate Schedule for new Customers or for Customers without at least one full year of usage history will be based on reasonably anticipated usage. N

CHARACTER OF SERVICE

The nature of Service provided by Company to Customer under this Rate Schedule is firm sales Service. Any reclassification or change in quantity or character of Service to Customer will be subject to procedures set forth in the Company's Service Regulations. N

MARGIN RATE	Winter (November-March)	Summer (April-October)	
Monthly Charge	$225.00	$225.00	I
Commodity Charge (per therm)	$.35400	$.30000	R

MONTHLY CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the Commodity Charge for gas delivered. The Monthly Charge will be billed from the date of initial service until service is terminated at the Customer's request. N

COMMODITY CHARGE

The rate per therm shall be billed on the quantity of gas delivered by Company to Customer's premises. N

BACKUP SERVICE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

Input shall be based upon individual Customer's applicable gas equipment rating in:

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$$\frac{\text{BTU/Hour x 10 hours}}{\text{100,000 BTU}} = \text{TH}$$

SERVICE AGREEMENTS

All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS

All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE

In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS

Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations and the operation of Rate Schedule 316.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY

All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgment as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, Company's Service Regulations, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee. S

SERVICE INTERRUPTION AND CURTAILMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service" and Company's Service Regulations. N

WEATHER NORMALIZATION ADJUSTMENT

Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider".

APPLICABLE DOCUMENTS DEFINING OBLIGATIONS OF THE COMPANY AND ITS CUSTOMERS

The applicable documents defining the obligations of the Company and its Customers are those described in Section 1 of the Company's Service Regulations. N

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RATE SCHEDULE NO. 362
Medium General Service – Value Rate

AVAILABILITY

Gas service under this Rate Schedule is available in the area served by the Company in the State of Tennessee to any full requirements non-residential Customer whose average daily usage is equal to or greater than 20 dekatherms per day but less than 50 dekatherms per day and whose Summer Load Percentage (SLP) is greater than 30%. Average daily gas usage will be based on the Customer's usage during the most recent calendar year ended on December 31 and adjusted for cycle length. SLP will be determined based upon the percentage of the Customer's total annual usage represented by the Customer's seven (7) month summer usage (April – October). Availability of this Rate Schedule for new Customers or for Customers without at least one full year of usage history will be based on reasonably anticipated usage.

Reclassification of customers between rate schedules will be based upon procedures set forth in the Company's Service Regulations as approved by the Tennessee Regulatory Authority.

MARGIN RATE	Winter (November-March)	Summer (April-October)
Customer Charge (per month)	$75.00	$75.00
Commodity Charge (per therm)		
1st 5,000 therms	$.35400	$.30300
Over 5,000 therms	$.35400	$.30300

D

MONTHLY CUSTOMER CHARGE

A charge will be billed monthly to all Customers for the availability of gas service. This charge will be in addition to the commodity charge for gas delivered. The Customer charge will be billed from the date of initial service until service is terminated at the Customer's request.

BACKUP RATE

When gas service is being supplied for use as a Backup Service for the dual-fuel heat pump or for similar use where the Customer's equipment is specifically designed by the manufacturer or is modified by the Customer or others for the purpose of using natural gas as the equipment's backup energy source, there shall be payable monthly in addition to all and other charges under this Rate Schedule a Backup Service Demand Charge individually determined for each Customer based upon the Customer's applicable gas equipment input rating. The per therm Demand Charge shall be equal to the unit Demand Charge applicable to the Company's firm industrial rate schedules.

Input shall be based upon individual Customer's applicable gas equipment rating in:

$$\frac{\text{BTU/Hour x 10 hours}}{} = \text{TH}$$

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100,000 BTU

SERVICE AGREEMENTS
All Customers purchasing gas pursuant to this schedule shall be subject to the Company's standard contracts and/or service applications and subject to the Company's Rules and Regulations as filed with the TRA.

PAYMENT TERMS
All bills for service are due upon presentation and the net rates are applicable if payment is made on or before the last date of payment stated on the bill. Payments made after that date shall be for the gross amount which is greater by five percent (5%) than the net billing.

RETURNED CHECK CHARGE
In the event a Customer's check for payment is returned to the Company marked NSF (Non Sufficient Funds) the Customer will be assessed a charge of $20.00.

ADJUSTMENTS
Bills for service are subject to adjustment caused by changes in the cost of purchased gas in accordance with Rule No. 1220-4-1-.12 of the TRA Rules and Regulations.

Purchased gas adjustments and all applicable taxes and fees are in addition to the above stated margin rates in accordance with The Rules, Regulations and Orders of the TRA and Laws of the State of Tennessee.

SERVICE AVAILABILITY
All requests for new and additional service or the transfer of existing service to higher priority end use will be considered based upon the Company's judgement as to the available gas supply, Customer's load factor or use pattern, end use, impact on the local economy, and The Rules, Regulations, and Orders of the TRA and Laws of the State of Tennessee.

SERVICE INTERRUPTION AND CURTAILMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 306, "Schedule for Limiting and Curtailing Service".

WEATHER NORMALIZATION ADJUSTMENT
Gas service under this schedule is subject to the provisions contained within TRA Schedule No. 315, "Weather Normalization Adjustment Rider".

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APPENDIX A

CUSTOMER AGENT AGREEMENT

This Customer Agent Agreement ("Agreement") is made this _____ day of _____, 20__, by and between Piedmont Natural Company, Inc. ("Piedmont") and _____ ("Agent").

WHEREAS, Piedmont's natural gas transportation tariffs provide for the ability of customers receiving Piedmont's transportation services to designate and utilize a third-party agent for purposes of making nominations for and delivering natural gas to Piedmont on behalf of such customers and managing imbalances on the Piedmont system resulting from such activities; and

WHEREAS, in undertaking such activities on behalf of Piedmont's customers, such Agents have the capacity to create material economic and operational risks for Piedmont and its customers; and

WHEREAS, Agent desires to act as a Customer Agent on Piedmont's system; and

WHEREAS, Piedmont is willing to permit Agent to operate on its system under the terms and conditions set forth herein and under the parameters of Piedmont's approved tariffs and service regulations.

NOW, THEREFORE, in consideration of the premises, and other good and valuable consideration the receipt and sufficiency of which is hereby acknowledged, Piedmont and Agent agree as follows:

1. Establishment and Maintenance of Creditworthiness. Each Agent must establish credit with Piedmont in the form of a Letter of Credit, escrow deposit, parental guaranty, or otherwise, in form and substance acceptable to Piedmont, in an amount equal to or greater than the dollar value obtained by the following formula at all times:

> The higher of Agent's average daily load for the previous month or Agent's First-of-Month confirmed daily nomination quantity for the new month x 3 days x (NYMEX prompt month close) x 1.25.

Each month, prior to nominating transactions for the first of the month business, an evaluation will be made to ensure that the established credit does not fall below the value obtained from the formula shown above. In the event Agent's established credit falls below the value obtained through application of the formula shown above, either during this monthly evaluation or at any other time, Piedmont may require that the value of said Letter of Credit, escrow deposit, parental guaranty, or other form of assurance be changed at any time in order to reestablish adequate creditworthiness hereunder. In the event Agent fails to establish creditworthiness as set forth above, or fails to comply within 5 days with directions from Piedmont to increase the amount of its credit instruments as provided herein, then Agent's right to conduct business on the Piedmont system shall be suspended until such time as Agent shall be in compliance with the creditworthiness provisions set forth herein (including any requirements to increase said creditworthiness).

2. Customer Agent Imbalance Restrictions. Agent shall not create a cumulative intra-month imbalance which exceeds three times Agent's aggregate First-of-Month confirmed daily nomination quantity. If this cumulative month-to-date imbalance restriction is exceeded at any time, then Agent's authorization to conduct business on Piedmont's system shall be immediately suspended except to the extent of transactions designed to reduce Agent's cumulative month-to-date imbalance. Upon any such suspension, Agent's authorization to conduct business on the Piedmont system shall not be restored until such time as Agent is in full compliance with the provisions hereof and all applicable provisions of Piedmont's tariffs and service regulations.

3. Allocation of Imbalance Quantities/Penalties. Concurrent with the submission of monthly nominations, Agent shall provide Piedmont with a schedule of allocated nominations for customers to be served by Agent for the following month. This allocation shall serve as the basis for resolving imbalances with Agent's customers to the extent those imbalances are not resolved by Agent. In the event Agent fails to submit such schedule, and further fails to resolve any monthly imbalance during the term hereof, those imbalances and any attendant penalties shall be allocated to Agent's customers, *pro rata*, based upon the actual usage of each such customer during the month to which the unresolved imbalance and/or penalties is attributable.

4. Failure to Comply with Operational Notices, and Agent Creditworthiness and Imbalance Requirements. If Agent fails to adhere to the imbalance and credit requirements set forth above, or to obey specific instructions issued by Piedmont and designed to preserve the operational integrity of Piedmont's system, Agent (a) shall be subject to the Unauthorized Over Run Penalty provisions of Piedmont's Rate Schedule 306, and (b) shall have its right to transact business on Piedmont's system suspended.

5. Term. This Agreement shall become effective as of the date first written above and shall continue in full force or effect until terminated by either party hereto upon sixty (60) days written notice.

6. Supplemental Nature of Agreement. This Agreement is supplemental to the provisions of Piedmont's approved tariffs and service regulations, the provisions of which shall also apply to services rendered hereunder. As such, the restrictions and requirements set forth herein are cumulative in nature and in addition to any other imbalance or penalty provisions set forth in Piedmont's approved tariffs and service regulations.

7. Billing and Payment. Billings to Agent for any amounts due hereunder, and payments by Agent on such billings, shall be made in a manner consistent with the billing and payment provisions of the underlying transportation tariffs pursuant to which service is rendered.

8. Miscellaneous.

A. Modification. This Agreement may not be modified or amended except by the execution of a written agreement by the parties hereto.

B. Waiver. No failure by any party to enforce this agreement with respect to any default in the performance of any of the provisions of this Agreement shall operate or be construed to operate as a waiver thereof or of any similar future default.

C. Assignment. This Agreement may not be assigned by any party hereto without the express written consent of the other party hereto.

D. Jurisdiction. This Agreement and the respective obligations of the parties hereto are subject to all valid laws, orders, rules and regulations of the Tennessee Regulatory Authority and any other governmental bodies having jurisdiction.

E. Conflict of Laws. The construction, interpretation, and performance of this Agreement shall be in accordance with the substantive laws of the State of Tennessee without regard to any conflicts of laws provisions thereof.

IN WITNESS WHEREOF, the undersigned parties have executed this agreement as of the year and date first written above.

AGENT

_____
By:_____
Title: _____

PIEDMONT NATURAL GAS COMPANY, INC.

_____
By:_____
Title:_____

MAILING ADDRESS
Please submit to: Transportation & Pipeline Services
Piedmont Natural Gas Company
P.O. Box 33068
Charlotte, N.C. 28233

OR

Transportation & Pipeline Services
Fax Number: (704) 364-8320

Piedmont Natural Gas Company, Inc. (hereinafter referred to as "the Company"), in its Tennessee service territory, will make free service calls, within certain broad guidelines, around-the-clock on customer appliances connected to our mains. Those service requests requiring immediate attention will be answered as soon as possible. Those of less urgent nature will be answered on a scheduled basis according to the workload. In either case, the Company will make every effort to answer each customer's call promptly and to leave all appliances operating at maximum efficiency.

Free Services (1220-4-5-.06(iii))

The Company provides the following services at no charge to the customer during normal working hours (Mon - Fri, 8am - 5pm, excluding Holidays): [C]

- Install gas meters and regulators for new customers
- Turn-on, turn-off, & service gas meters
- Check for gas leaks
- Investigate the possible presence of carbon monoxide
- Cut off pilots
- Disconnect appliances (disconnect & cap existing pipe only) in connection with a meter turn-off
- Food Service equipment service including leveling, adjusting, or calibrating
- Diagnostic time or time to provide an estimate for jobbing work
- Quotes for appliance installation
- The first light-up of the heating season on central furnaces (a flat charge applies for each additional light-up) [C]
- Gaslight turn-on and re-lighting
- Service leased water heaters
- Service appliances other than central heating systems or gas air conditioners (no parts needed) including:
  - Service calls to diagnose problems
  - Check gas pressure
  - Adjust burners
  - Clean air mixers
  - Light pilots
  - Clean & adjust pilots
  - Examine flue connections & check draft
  - Check and calibrate thermostats & controls
  - Check appliance wiring & other electrical components
- Service non-central heating systems where safe and ready access is available including floor furnaces, wall furnaces, space heaters and unit heaters including: [C]
  - Service calls to diagnose problems
  - Gas and air adjustments on burners and pilot assemblies
  - Adjustments of controls and thermostats
  - Minor electrical repairs that do not require materials
- Service Arkla, Bryant, and other gas-fired air conditioners including:
  - Service calls to diagnose problems
  - Gas and air adjustments on burners and pilot assemblies

- Checks of controls and thermostats
- Pumping of water-cooled units to maintain operation
- Purging of non-condensables from air-cooled units

Note: When an appliance is not operating, every effort will be made to answer the call without delay, and in most circumstances, on the same day. Should repair work be required, parts needed to complete the repair will be ordered from the manufacturer and installed if the customer so desires. There is, however, a charge for this service.

The company will also provide immediate response to any hazardous situation that might cause threat to life or property after normal working hours (Mon – Fri, 5pm - 8am; Sat; Sun; & Holidays) at no charge, including:

- Fire or explosion
- Gas leak
- Damaged gas main or service (parts & labor may apply)
- Gas appliance that won't cut off
- Carbon monoxide investigation
- Leased water heater service within 24 hours

Services For Which There Are Charges

- Installation or connection of gas appliances
- Reconnects of gas appliances
- Disconnects of gas appliances except when performed in connection with a meter turn-off [N]
- Repair of gas appliances where parts are needed (except central systems)
- Repair or replacement parts, electrical equipment, or thermostats on Arkla or Bryant gas air conditioners beyond Service/Warranty Contract
- Cleaning condensers and condensate lines on gas A/C units
- Gaslight repairs and reconditioning
- Miscellaneous pipe work
- Change outs and reconnects of food service equipment
- Repair of gas air conditioning units installed after January 1, 1975; units on which the Warranty/Service Contract has expired; and units or installations not approved by the Company's Service Department
- Work involving replacement of filters and out-of-warranty parts [C]
- After hours work that requires a repair including commercial cooking and water heating equipment (the customer may be given the option for jobbing repair at the current overtime rate, if time and workload permits)

Work the Company Does Not Provide

- Replacement of filters in central heating equipment
- Installation, connection, or repair of unit heaters and central heating equipment
- Repair or replacement of unit heaters and other equipment requiring an electrician

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- Repair or installation of any equipment that has not been tested and approved by applicable US safety standards or where gas appliances are not used in accordance with the manufacturer's listing [C]
- Repairs on heating equipment that requires parts will not be made except on those units sold by the Company prior to May 1, 1974. In addition, the Company does not install furnace filters
- No work will be performed on electrical air conditioning units installed with a gas furnace (this work will be referred to the installer or mechanical contractor)

Charges for Work

Unless a charge for work contemplated by this Section 1 is specified herein, all work performed for Customers, on or related to appliances, fuel and gas lines (behind the Company's meter), gas lights or other equipment shall be performed at the Company's standard rates and charges. Such charges may be modified or adjusted from time to time at the Company's discretion. [N]

Use of Credit Cards by Customers

Company will accept credit card payments from residential customers receiving service under Rate Schedule 301 and from natural gas vehicle fuel customers receiving service, at Company-owned facilities, under Rate Schedule 342. Company will not accept credit card payment of bills from Customers receiving service under any other Rate Schedule or contract.

Termination Policy

Reasons for Termination of Service or Denial of Service (1220-4-5-.18)

Service may be refused or discontinued for any of the reasons listed below. Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued. [C]

1. Without notice in the event of a condition determined by the utility to be hazardous
2. Without notice in the event of customer use of equipment or the utility's service to others
3. Without notice in the event of tampering with the equipment furnished and owned by the utility
4. Without notice in the event of unauthorized use
5. For violation of and/or non-compliance with the utility's rules on file with and approved by the Tennessee Regulatory Authority
6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Tennessee Regulatory Authority
7. For failure of the customer to permit the utility reasonable access to its equipment

8. For non-payment of bill provided that the utility has made a reasonable attempt to effectively collect and has given the customer written notice that he has at least five (5) days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied
9. For failure of the customer to provide the utility with a deposit as authorized by 1220-4-5-.14 of the Tennessee Regulatory Authority Statutes
10. For failure of the customer to furnish such services, equipment, permits, certificates, and/or rights-of-way, as shall have been specified by the utility as a condition to obtaining service, or in the event such equipment or permission are withdrawn or terminated.

Insufficient Reasons for Denying Service (1220-4-5-.19)

The following shall not constitute sufficient cause for refusal of service to a present or prospective customer:

1. Delinquency in payment for service by a previous occupant of the premises to be served
2. Failure to pay for merchandise purchased from the utility
3. Failure to pay for a different type of class of public utility service
4. Failure to pay the bill of another customer as guarantor thereof
5. Failure to pay a back bill rendered in accordance 1220-4-5-.17(a) of Tennessee Regulatory Authority Statutes.

Disconnection

The Company has the right to shut off gas from any consumer who may be in arrears for a longer period than twenty (20) days in paying for gas furnished hereunder or under any other prior or subsequent agreement, or for gas used by the consumer at the consumer's present or any prior subsequent address. The said twenty-day period commences to run from the date the bill was rendered. The Company will not shut off gas for non-payment without first mailing a notice to the consumer giving him seven (7) calendar days to pay the bill in arrears.

The Company will not terminate service during any 24-hour period, as measured from 8:00 am on the planned date of termination, where the forecasted low temperature, as determined by the National Weather Service, is 32 degrees Farenheit or below.

Reinstating Service

If natural gas service is disconnected for nonpayment, service will be restored after the customer has paid the total amount past due, paid the reconnection charge and paid a deposit.

Third-Party Notification

At the customer's request, the Company will send a copy of any disconnection notice to a designated third party. However, the designated third party is not responsible for paying the bill.

Medical Emergencies and Life Support Devices

The Company will delay disconnection of gas service for 30 days if a physician, public health officer or social service official certifies in writing that discontinuing gas service will worsen an existing medical emergency for a permanent resident of the premises where services are rendered. A prompt request is important. During the 30-day extension, payment of the bill must be guaranteed by another person or entity that is acceptable to the Company.

The Company will not disconnect service at the service address if there are natural gas appliances that are critical to maintaining the health of one or more permanent residents. The Customer Service Department must be contacted to determine whether a gas appliance is considered a life-support device.

Notice of Rights and Remedies

Should the Customer request help in paying his natural gas bill the Company will provide the customer with a list of community agencies that provide aid in paying their natural gas bill. The company will also, in some cases, make alternative pay arrangements if the customer is temporarily unable to pay his natural gas bill. However, if such an agreement is made the customer gives up their right to dispute the amount due under the agreement. If the customer does not fulfill the terms of the agreement, the Company may disconnect service and a new pay agreement will not be offered before we disconnect service.

If the Customer wants to appeal an unfavorable decision regarding a natural gas bill, they may contact the Tennessee Regulatory Authority's Complaint Division, 460 James Robertson Parkway, Nashville, TN 37219 (615-741-3939 or 800-342-8359). This must be done before the net due date if the dispute involves a disconnection notice. The Company will not disconnect service for nonpayment of the disputed portion of the bill while it is being reviewed. The Customers right to appeal will not expire if delay on the Company's part makes it impossible to contact the TRA within the required time period. The Customer also has the right to suspend payment of the disputed portion of the bill while the dispute procedures mentioned above are in progress.

Process for Obtaining Consent to New or Changed Service

All Customers shall be required to make application to the Company for new or changed Service under any of the Company's Rate Schedules in such form and manner as may reasonably be required by the Company. Such applications shall be required in order to initiate Service under any Rate Schedule irrespective of whether Customer is then

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receiving service under any other Company Rate Schedule and for changes in the quantity of Service to be provided under an existing Rate Schedule. At a minimum, such application shall set forth the date of the application, the name of the Applicant, the location of the Premises for which Service is requested, the type of Service applied for and estimated gas consumption. Prior to being obligated to provide Service to Customer pursuant to such application, Company shall conduct an examination and review of Customer's application for Service to determine: (1) that the Company has the operational ability to provide the Service requested, including the requisite upstream supply and/or capacity assets; (2) that the requested Service will not impede or interfere with the Company's ability to maintain Service to existing Customers with the same or a higher priority of service; (3) that provision of the requested Service will not have a materially adverse impact on the Company's ability to recover its approved margin; (4) that provision of the requested Service is economically feasible; and (5) that Customer is creditworthy as determined in accordance with the Commission's Rules and the Company's procedures. Provided that the Company's review and analysis indicates that Service can be provided as requested, the Company will then approve the requested Service. Company shall have no obligation to provide the requested Service absent such approval.

When the requested Service is to be provided to a Residential, Small or Medium General Service Customer, and the provision of such Service is economically feasible, the application and the Company's acceptance thereof may be oral at the Company's option. In such event, the Company's applicable Rate Schedules and these Service Regulations shall become effective and applicable to any Service rendered to such Applicant in the same manner as if the Company's standard written form of application for Service had been signed by the Applicant and accepted by the Company. Upon the provision of Service by the Company to such Customer, such oral service agreement shall be presumed to exist in any case where there is no written application accepted in writing by the Company.

In the event a Customer receiving Service under the Company's commercial or industrial (large general) sales Rate Schedules anticipates a significant reduction in its gas consumption, it shall provide prompt notice thereof to Company.

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Customer Classifications

Residential Rate Service Classification. All Residential Rate Service shall be provided pursuant to the Company's Rate Schedule 301.

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Commercial Rate Service Classification. All Commercial Rate Service shall be provided pursuant to the Company's Rate Schedules 302 and 352. Classification between Rate Schedules 302 and 352 shall be based on the following criteria:

A. Definitions: As used in Commercial Rate Service Classification, the following terms shall have the meanings assigned below:

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(1) "Annual Review Period" shall mean the twelve (12) months ended on December 31 of each year.

(2) "Actual Monthly Usage" shall mean the actual natural gas volumes consumed by the Customer during the highest month of consumption during the Annual Review Period as reflected on the Company's invoices for the Customer.

(3) "Classification Usage" shall mean the usage criteria that establishes the minimum and/or maximum average daily usage that must be maintained in order to receive service under a rate schedule. The classification usage for Rate Schedule 302 shall be less than an average of 20 dekatherms per day. The classification usage for Rate Schedule 352 shall equal or exceed an average of 20 dekatherms per day but be less than an average of 50 dekatherms per day. C

(4) "Involuntary Curtailment Days" shall mean those days or portions of days in the highest month of consumption during a given Annual Review Period where curtailment of the Customer's natural gas service was imposed by the Company's decision to curtail.

(5) "Service Days" shall mean 30 days less the number of Involuntary Curtailment Days.

(6) "Average Daily Usage" shall be the Customer's Actual Monthly Usage within the Annual Review Period divided by the number of Service Days.

B. Procedures:

(1) At the conclusion of the Annual Review Period of each year and prior to June 1st of the ensuing year, the Company will determine for each customer served under Rate Schedules 302 and 352 that Customer's Average Daily Usage. C

(2) Those customers currently receiving service under Rate Schedule 302 whose Average Daily Usage is equal to or exceeds 20 Dekatherms a day, will be transferred to Rate Schedule 352, effective on the first day of June following the most recent Annual Review Period. C D

(3) Those customers currently receiving service under Rate Schedule 352 whose Average Daily Usage in each of the most recent two (2) Annual Review Periods is less than 20 Dekatherms a day, will be transferred to Rate Schedule 302 effective on the first day of June following the second, and most recent, Annual Review Period. C

(4) Those customers currently receiving service under Rate Schedule 302 or 352 whose Average Daily Usage in each of the most recent two (2) Annual Review Periods is equal to or greater than 110% of 50 dekatherms per day will be transferred to Rate Schedule 303, 304, 313, or 314 as applicable. C

C. Exceptions: If a customer currently being billed under Rate Schedule 302 adds natural gas equipment that increases the Customer's Average Daily Usage to the point where the customer will qualify for Rate Schedule 352 the Company may, upon notification from the Customer and subject to installation verification by the Company, transfer the Customer to the new Rate Schedule prior to June 1 of that year. C

Industrial Rate Service Classification. Rate service classification under the Company's Rate Schedules, 303, 304, 313 and 314 shall be based on the following criteria:

A. Definitions: As used in rate service classification, the following terms shall have the meanings assigned below:

(1) "Annual Review Period" shall mean the twelve (12) months ended on December 31 of each year or the regularly scheduled meter reading nearest December 31.

(2) "Actual Monthly Usage" shall mean the actual natural gas volumes sold or transported for the Customer by the Company during the highest month of consumption during the Annual Review Period as reflected on the Company's invoices for the Customer.

(3) "Classification Usage" shall mean the usage criteria that establishes the minimum and/or maximum average usage that must be maintained in order to receive service under any rate schedule. For existing Customers, the classification usage for Rate Schedule 302, 332, 352, 362 shall not exceed an average usage of 55 dekatherms per day. For existing Customers, the classification usage for Rate Schedules 303, 304, 313 and 314 shall exceed an average usage of 45 dekatherms per day.

(4) "Involuntary Curtailment Days" shall mean those days or portions of days in the highest month of consumption during a given Annual Review Period where curtailment of the Customer's natural gas service was imposed by the Company's decision to curtail.

(5) "Service Days" shall mean 30 days less the number of Involuntary Curtailment Days plus the number of days that Customer consumed an alternative fuel to natural gas.

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(6) "Average Dekatherm per Day" shall be the Customer's Actual Monthly Usage within the Annual Review Period divided by the number of Service Days.

B. Procedure:

Step 1. During January and February of each year, the Company will determine for each Customer served under Rate Schedules, 303, 304, 313 and 314 the Customer's Average Dekatherm per Day usage for each of the two most recent Review Periods.

Step 2. A Rate Schedule 302 or 352 Customer whose usage is 110% of the 50 dekatherms threshold in the two most recent Review periods will be transferred to Rate Schedule 303, 304, 313 or 314, as applicable. A Rate Schedule 303, 304, 313 or 314 Customer whose usage is equal to or less than 90% of the 50 dekatherms threshold in both of the most recent two Review Periods will be transferred to the appropriate Small or Medium General Service Rate Schedule. Customers receiving service under Rate Schedules 303 or 304 shall be eligible to elect transportation service to be effective with the rate reclassification. C

All changes in rate classification under this section shall be effective on the first day of June following the review.

Step 3. Customers who are reclassified shall be notified of the change in rate schedule, and receive a copy of the tariff sheets applicable to his old and new rate schedules at least 21 days prior to the effective date of the change.

C. Exceptions: If a Customer adds or retires a major piece of gas-burning equipment, changes the hours of operations or otherwise materially alters the Customer's business that will clearly increase, or decrease, the Customer's consumption on an ongoing basis to a level that will change the Customer's ability to qualify the Customer for a particular rate schedule, the Customer shall report such changes to the Company and afford the Company an opportunity to inspect the change in equipment and to meet with the Customer to review and discuss the anticipated future level of consumption. If, after such inspection and meeting, the Company is satisfied that reclassification is appropriate, the reclassification will occur within two months after the new equipment is in place and operational, or the retirement is completed, and the first meter reading reflects the higher anticipated usage resulting from the new equipment or the lower anticipated usage resulting from the retirement. Any reclassification pursuant to this paragraph is subject to correction if actual experience so warrants. If the reclassification results in qualification for service under Rate 303 or 304, the Customer shall provide an election form one week prior to reclassification if a transportation election is

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desired. Otherwise, service will be provided under Rate Schedule 303 or 304, dependent upon rate qualification.

Requirements: Upon reclassification from Rate Schedules 302 or 352 to either Rate Schedule 303, 304, 313, or 314, Customer will be responsible for installing and maintaining, at the Customer's expense, a dedicated 110v electrical service in a location suitable to provide electrical service for the Company's telemetering equipment. C

Applicable Documents Defining Obligations of the Company and its Customers

The obligations of the Company to provide Service and the obligations of the Customer upon receipt of Service are governed by and set forth in (a) applicable statutes, including those set forth in Chapter 65 of the Tennessee Code Annotated, (b) applicable Tennessee Regulatory Authority Rules, Regulations, and Orders, (c) applicable tariffs or Rate Schedule(s), (d) these Service Regulations, (e) any application, agreement, Special Contract, or similar document executed by Customer and approved, as necessary, by the Authority pertaining to such service, and (f) any standard operating procedures of the Company reasonably necessary for the provision of such Service and administered on a nondiscriminatory basis. Copies of Chapter 65 of the Tennessee Code Annotated, applicable Authority Rules, Rate Schedules, and these Service Regulations are available from the Company for public inspection, as are copies of forms of applications, agreements, and other documents approved by the Authority. A copy of the Authority's Rules are available at the Authority's Web Site at www.state.tn.us/tra/. Unofficial copies of the Company's Rate Schedules and Service Regulations are also available at the Company's Web Site at www.piedmontng.com.The Company shall provide all new non-residential Customers with a copy of the applicable Rate Schedule(s) and written application for Service and/or other documents executed by the Company and the Customer pertaining to such Service. After a Customer has executed a written application and/or contract, no promise, statement or representation by an employee or agent of the Company or by any other person inconsistent with the written application and/or contract shall bind the Company to provide Service or to change the terms and conditions upon which Service will be rendered unless the same is in writing and is executed by an authorized representative of the Company. In the event there is a conflict between these Service Regulations and the provisions of the applicable currently effective Rate Schedule, the provisions of the Rate Schedule shall govern. The Authority Rules shall govern in the event of a conflict with these Service Regulations. The Company may not make any representation that conflicts with Authority Rules, its Rate Schedules or these Service Regulations. N

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Applicable Documents Subject to Change

All of the documents defining the obligations of the Company to provide Service and the obligations of the Customer upon the receipt of Service are subject to change from time to time upon order of or approval by the Authority and by other duly constituted governmental authorities. The Company does not undertake to advise any Customer of any such change except as may be required by the Commission or other duly constituted governmental authority. N

Priority of Service

The Company has established the following categories of service in order of priority:

1. Residential, small commercial (less than 50 MCF on a peak day), school, hospital, police protection, fire protection, sanitation, or correctional facility requirements
2. Essential agricultural requirements
3. Large commercial requirements (50 MCF or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs, pipeline customer storage injection requirements, and firm industrial sales up to 300 MCF per day
4. All industrial requirements not specified in 2, 3, 5, 6, 7, 8, 9 or 10
5. Firm industrial requirements for boiler fuel use at less than 3,000 MCF per day, but more than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements
6. Firm industrial requirements for large volume (3,000 MCF or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements
7. Limited Availability requirements of less than 300 MCF per day, where alternate fuel capabilities can meet such requirements
8. Limited Availability requirements of more than 300 MCF per day but less than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements
9. Limited Availability requirements of intermediate volumes (from 1,500 MCF per day through 3,000 MCF per day), where alternate fuel capabilities can meet such requirements
10. Limited Availability requirements of more than 3,000 MCF per day, but less than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements
11. Limited Availability requirements of more than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements.

Meter Turn On

There is no charge for meter turn on for a new customer. There will be a flat charge for meter turn on for an existing customer or member of same family or household. For turning on meters shut off for non-payment of bills there will be a flat charge for meter turn on plus payment of all past due bills. The Company may also secure an additional customer deposit. If an existing customer requests that his/her meter be turned off for the summer to

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avoid minimum bills during the summer period and then requests the Company to turn the meter back on, the flat charge for meter turn on will apply.

Gas Wastage (1220-4-5-.06(iv))

Excessive gas consumption without knowledge by the customer may possibly be the result of gas leakage or appliance malfunction. Gas bill adjustments generally will not be permitted for improper and/or inefficient operation of gas appliances or for gas leaks. Adjustments for all special cases will be based upon individual merit dependent upon such factors as prompt action by the customer, the nature of the problem, maintenance of facilities by the customer, the time period involved, etc. An example might possibly be a hot water relief valve stuck open or a broken hot water line on a gas water heater. All such special adjustments shall not exceed 35% of the wastage and shall be approved by the Director of Customer Service (residential) or the General Manager of Marketing (commercial). Wastage shall be based on Service Department inspection or Customer Service Department researches. The Director of Customer Service shall determine consumption rates. Duration of the adjustment shall not exceed 30 days. Where such gas appliance malfunction or gas leakage was directly caused by actions of Company personnel or occurred within 30 days of the date the work was performed by Company personnel, the Company will grant 100% credit of wastage to the customer. The amount of wastage will be approved by the Director of Customer Service and not exceed a period of 30 days. C

Title to Facilities

The title to all facilities including mains, gas service lines, meters, and accessory equipment up to and including the outlet of the meter assembly shall be vested in the Company, notwithstanding any charge which may be made to the customer for extending service.

Appliance Classifications

Major appliances

- natural gas heating systems utilized as primary heating source in the structure
- gas air conditioners
- gas water heaters

Minor appliances

- clothes dryers
- gas fireplaces
- gaslights
- grills
- incinerators
- log starters
- logs

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- ranges
- swimming pool gas water heaters

General Installation / Connection & Repair Policy

The Company will provide equipment, labor, and materials to install, repair, and service gas-fired equipment. Such installations, repair, or service shall be charged at Company's standard rates and charges. The installations and repairs will be performed in accordance with all applicable codes and licensing requirements. The Company reserves the right to decline such work, on a non-discriminatory basis, if the conditions involved in such work are not consistent with the safe or efficient completion of such work. All natural gas appliance installations on Company lines shall comply with the current version of the International Fuel Gas Code adopted by local authorities. All appliances installed, repaired or serviced by Company must also be tested and approved by US safety standards and used in accordance with the manufacturer's listing. The Company reserves the right to refuse to connect those appliances which, in its judgment, do not conform to appropriate safety requirements. C

D

Water Heaters

The Company will install and repair, including dip tube replacement, residential water heaters on the basis of its standard rates and charges. For repairs of commercial gas water heaters, the customer is to be referred to local dealer or plumber. C

Dryers

The Company will install and repair residential dryers on the basis of the Company's standard rates and charges. Repair requests on commercial gas clothes dryers, other thermocouples or other parts normally stocked by our storeroom, will be referred to the appropriate dealer for servicing. C

Gas Grills

The Company, as part of its free service program, will make burner air and gas adjustments, check controls, and assist in problem diagnosis on a no-charge basis. Installations of and repairs on gas grills will be charged on the basis of the Company's standard rates and charges. Cleaning and painting of the grill will be the responsibility of customer. The Company may also perform the following on the basis of the Company's standard rates and charges: C

1. Post Replacement:;
2. Repairs to Cut or Damaged Tubing;
3. All Other Repairs.

Gaslights

With regard to gaslights, the Company will turn on, re-light and replace mantles without charge to the residential customer. Should the residential customer wish to replace the mantles himself, the Company will, upon request, mail to him replacement mantles for residential use in his gaslights without charge. Residential customers may also pick up free replacement mantles for use only in their gaslights at the Company's storeroom. The same gaslight service policies apply to commercial/industrial customers except they will be charged for the mantles. Subdivision entrances and multi-family developments do not qualify for residential use. Services do not include the painting of gaslights or glass cleaning; these are considered the owner's responsibilities.
The Company will recondition the customer's gaslight, including replacement of mantles, cleaning and/or replacement of glass panes as required, and painting repair of gaslight as necessary, for a flat labor charge plus cost of replacement parts (other than mantles). In the case of multiple gaslights on the same piece of property, the labor charge shall apply only to the first light. For each additional light on the same property, an additional charge plus parts (other than mantles) will apply. The same policy applies to commercial customers except they will also be charged for mantles. Installation of and repairs on gaslights, including those listed below, will be charged on the basis of the Company's standard rates and charges. The Company may also perform the following: C

1. Post and/or Light Head Replacement: All customers needing to purchase a gaslight head will be referred to the Home Energy Center;
2. Repairs to Cut or Damaged Tubing: A service representative can sometimes perform this work, but generally a three-man fitting crew is required.
3. Complete Replacement: The customer shall be referred to the Company's Home Energy Center. If the customer provides a replacement light head and post of the same basic type, the Company will connect the replacement;
4. All Other Repairs.

Gas Logs & Log Starters

All installations of or repairs on gas logs and log starters will be charged on the basis of the Company's standard rates and charges. C

Other Miscellaneous Residential Gas Appliances

All installations of or repairs on other approved gas appliances will be charged on the basis of the Company's standard rates and charges. C

D

Appliance Parts Broken by Company Personnel

From time to time when our service personnel are repairing a customer's gas appliance, other adjacent parts become broken during the course of the repair. Such instances leave a question as to whether the customer should be charged for that additional part. Such decisions shall be at the discretion of the supervisor involved. The following guidelines should be of assistance.

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No Charge to Customer

1. Breakage caused by negligence on part of our personnel. In such cases, the employee will be counseled to avoid repetition.
2. Accidental breakage of part considered "relatively new" and our representative was using care and attention to work procedures.

Charge to Customer

1. Parts that may be broken after customer first being warned that we will use care in repair but the customer will be responsible for all parts involved. If the service representative has doubts about the condition of the appliance, he should so warn the customer initially.
2. Any parts broken which are not "relatively new" and in process of normal repair with our representative using reasonable care in work procedures. Where we make a mistake we'll stand behind it, but we will not unilaterally absorb the cost of other parts broken, they will be considered part of the job.

Sales to Employees

The following is applicable for active permanent employees, retired employees and retiree's surviving wife or husband until such time as survivor remarries:

1. Employees may purchase Natural Gas Appliances and accessories at cost from the Company. Appliances must be purchased for use only in the employee's own home. C
2. Pipe, pipe fittings and similar material carried in stock by the Company may be purchased by employees at warehouse cost, but these also must be used in the employee's own home and all such purchases must be approved by the Company. C

There is no intent in these rules for employees to unfairly benefit from Company discounts. The giving of false information to obtain a discount from the Company will be considered a cause for discipline.

D

Liquid Propane Conversion to Natural Gas

Any new conversion customer converting from liquid propane (LP) to natural gas will receive gas service line and meter installation on the same basis as any other residential or commercial customer. C

Residential

Conversion of residential gas dryers, grills, logs, furnaces or other appliances shall be performed on the basis of the Company's standard rates and charges. C

Commercial

Conversion of AGA approved residential gas appliances or commercial gas appliances in a commercial structure will be performed on shall be performed on the basis of the Company's standard rates and charges. C

Temporary Conversions to Liquid Propane

When deemed necessary by the Company, new construction and conversion customers will be temporarily converted to liquid propane at no charge. The conversion back to natural gas will also be performed by the Company at no charge.

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Company's Tennessee Service Regulations

Section 2 – METERS

Installation & Location

The Company performs standard meter installation at no charge to the customer. However, a customer desiring an underground meter installation will be charged for the additional cost. The most desirable and serviceable location for a new residential meter installation is on the outside of the structure, approximately four feet past the front wall, where it is not subject to damage from automobiles. The new meter shall be so located unless it is physically impractical or it interferes with customer's use of his property. C

The proper meter location for large outside commercial or industrial meters, especially those having multiple structures, is at the property line wherever possible. Under no circumstances shall a meter be located within 10 feet of a combustion air intake. Further, meters shall not be located within 3 feet of an ignition source such as heating or air conditioning equipment, water heaters, electric meters, switch gear, electric panels, etc.

The customer or owner must at all times provide a proper and accessible location for all meters and regulators. The following rules apply as well:

1. All meters installed on high-pressure services must be installed outdoors.
2. All "farm tap" meters shall be located at the main.
3. All meters served from standard and medium pressure mains shall be installed outdoors, except in those instances in which it is extremely difficult to do so or is very undesirable from the customer's viewpoint. In such cases, the meter may be installed indoors, at the discretion of the Company, if the installation conforms to applicable codes.
4. If a customer desires to use gas solely for swimming pool water heating, the meter shall be located at the house and the fuel line run from this point to the pool heater.
5. If located indoors, the meter shall not be located:
   a. Above the ground floor
   b. Less than 3 feet from a hot air furnace or boiler
   c. Less than 3 feet from a gas oven or hot water heater
   d. On or under stairways
   e. In bathrooms or adjoining clothes closets
   f. In small, unvented, or confined spaces
   g. Where subject to damage, extreme high temperature, or corrosion
   h. In entrances or exits so as to obstruct passage in any way
   i. Less than 10 feet from boilers or other sources of heat, if the meter capacity is 80B or larger

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Meter Relocation

Outside meters will be relocated when requested by the customer, however, the customer will be charged Time and Material.

Meter Testing

The Company maintains a regular program of meter testing and change-out to insure metering accuracy. Upon written request from the customer for a special test of his meter, the Company will inspect the meter at a reasonable time in accordance with provisions of Rules, Regulations and Statutes Governing Public Utilities as issued by the Tennessee Regulatory Authority. Such meters will be considered to register correctly if the error is not greater than plus or minus two percent (2%). If the meter is found to be registering incorrectly, the meter will be repaired or adjusted to conform to standards with no charge to the customer for testing or repair. If the meter is registering correctly, there will be a meter testing charge to the customer.

Meter Tampering or By-pass

The term "metered gas" is defined as "all gas that has passed through the customer's meter." It is Company policy to prosecute those persons involved where the Company finds evidence of meter tampering or by-pass. Such acts are illegal, as well as extremely dangerous, and Tennessee State Law provides for substantial punishment. In such cases, the customer or party involved will be charged for all gas used and the cost of meter repair including travel time and all other related expenses on a "Time and Materials" basis. At the Company's option, gas service may also be terminated. C

Meter Damage

The customer has a responsibility to provide reasonable protection for the Company's metering facilities from damage by his employees, customers, and the general public. It is not, however, his equipment and he cannot be expected to provide security such as guards, surveillance, enclosures, etc. to protect the Company's meters from acts of vandalism or from the general public. The Company selects and approves meter locations. If a location is in a drive, parking lot, alley, etc. where damage is likely, then it is the Company's responsibility to provide adequate protection such as posts, etc. In cases where the Company's metering facilities are damaged, with regard to actual damage responsibility, the following applies: C

1. If the customer or his employees cause damage (accidentally or purposely), then the customer should be billed for damages.
2. If a visitor, commercial vehicle, or general public vehicle damages a meter, damage relief should come from that person or firm causing the damage. Damage relief shall not come from the customer, unless it can be proven that the damage by a third party resulted from negligence on the customer's part.

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Company's Tennessee Service Regulations

Section 3 – FUEL LINES

Customer gas fuel lines installed on Company mains shall comply with all applicable codes and provisions of the current version of the International Fuel Gas Code adopted by the county in which the gas facilities operate. The care and maintenance of all customer-owned underground fuel lines is the responsibility of the customer. All piping carrying metered gas is considered a fuel line. When in place in a finished building, hidden from view and not easily accessible, the piping is considered a concealed fuel line. All fuel lines will be (a) standard threaded and coupled or welded steel minimum schedule 40 pipe (depending on operating pressure), or (b) plastic pipe or tubing of the following types: TR-418 PE 2306 – orange color, Drisco 7000 or 8000 PE 3406 – black color, or approved equal. N

Fuel Lines May

- Be installed underground in accordance with applicable codes to include corrosion protection.
- Be installed to serve any number of buildings if all the buildings are located on a single or continuous tract of land with common ownership.
- Be concealed if installed in accordance with applicable codes.

Fuel Lines May Not

- Be smaller than 1-1/4" coated steel or 1-1/8" x.090 wt Polyethylene (PE) tubing if installed underground (unless serving only gaslights, grills, or logs). Fuel lines to remote heating units may be smaller as approved by the Service Department. The Service Department will determine the size of fuel lines for mobile homes.
- Extend to or across property under different ownership.
- Cross any public street, alley, or highway. Fuel lines shall be sized to have a minimum pressure drop between the meter outlet and any appliance of 0.3-inch water column. Those fuel lines served from standard pressure distribution systems will be sized on 0.2-inch water column pressure drop.

Installation Charges

All fuel lines will be installed at the customer's expense with one exception: when determined necessary, the Company may choose to install a fuel line instead of a service line. In this event, ownership with maintenance responsibility shall remain with the customer. In such cases, footage of fuel line installed shall be equal to the footage of service line that would be "free service" if the customer were served in the usual manner (a "farm tap" customer is an example). Charges for residential underground fuel lines will be on the basis of the Company's standard rates and charges. Pre-installation estimates may be obtained from the Service Department (for plastic tubing) or the Construction Department (for all other underground fuel lines). The customer at his expense will replace N

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any sidewalk or pavement cut. The customer will be charged on the basis of the Company's standard rates and charges for all fuel line repairs made by the Company.

Commercial or Industrial Fuel Lines

Commercial or Industrial fuel line piping work will be performed by the Company according to applicable codes and licensing requirements. If the Company installs a customer's underground fuel line, the charges will be based on the Company's standard rates and charges. N

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Company's Tennessee Service Regulations

Section 4 – SERVICE LINES

Service lines are pipes used to carry unmetered gas from the main to the customer's meter. The preferred route of the service line will be from the nearest adequate main to four (4) feet beyond the customer's nearest building wall. Service lines, service relocations, and extensions may be installed in accordance with applicable codes by either the Company or by a contractor approved by the Company. The complete installation must be inspected and approved, prior to being backfilled, by the appropriate Company representative. In general, service lines should not be laid on vacant property adjoining the building to be served if there is likelihood that a building will be constructed on the vacant property. Service line installation policies are subject to conditions of gas supply and the Company's limited service attachment programs.

Customer Types

Residential

The Company will install free of charge 100 feet of service line for one major appliance, as defined in Section 1, where no main extension is required. The gas service line must extend along the route selected by the Company. In the event that the above conditions are not met, the service line installed for the customer must provide a reasonable return to the Company. If the customer wishes the facilities to be constructed along a route other than the route selected by the Company and/or if the gas service line is more than the length allowed above and/or the service to be rendered to the customer will not produce a reasonable return to the Company, the Company may require the customer to pay the excess cost of constructing the facilities along the alternate route or in excess of the footage allowed and/or to make a contribution which will permit the Company to earn a reasonable return. In all cases any pavement or sidewalk cut will be replaced by and at the customer's expense.

Commercial or Industrial

For permanent use and where revenues provide a reasonable return to the Company, the Company will install free of charge 100 feet of service line measured from customer's property line or four feet past the nearest building wall, whichever is less.

Exceptions

In cases where there is exceptional cost due to length of service, high pressure main, paving (such as crossing major street), rock, etc., these service orders shall be reviewed by the Engineering Department on a case-by-case basis to determine if they meet the main extension policy provided in Section 5. N

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Excess Service

Excess service refers to that portion of the total cost of a service line installed for a customer that is in excess of the Company's justifiable investment and is that portion of service line cost paid for by the customer.

Repairs

Repairs to service lines damaged by others shall be charged at the Company's actual repair costs.

Service Extensions

A service extension includes all piping carrying unmetered gas from the termination of the previous service line to the inlet of the meter. Service extensions and relocations shall be installed at the customer's expense.

Branch Services

Branch services will be permitted only when the point of junction of the two services is either in the public right-of-way or on a customer's property. In the latter case, written and notarized permission of the property owner must be obtained and filed with the Register of Deeds of the appropriate county. In the case of services requiring in-line valves, the service must be branched in the public right-of-way, and the Construction Department must confirm presence of a valve in each branch.

Multiple Buildings on Same Lot

In those cases where two or more buildings are located on the same lot in such a manner as to be reasonably suited to subdividing, the Company will, if requested, run separate service lines to these buildings. However, if the buildings are not so situated (e.g. garage apartments or combination commercial and residential buildings), the Company will not run separate services except where the full cost of the additional service from main to meter, including paving, is borne by the customer.

Service Line Enlargements

If the load through an existing service is so increased as to require a larger service line, the Company will enlarge the existing service to a point four (4) feet beyond the customer's nearest outside building wall without charge. Any enlargement of the service line beyond this point will be at the customer's expense. Any fuel line changes will be at the customer's expense.

Shopping Centers

A shopping center shall be considered as a single structure containing a minimum of 7,500 square feet of floor space and a minimum of four (4) tenants or business stores operating within the structure. The Company shall install one service line and one bank of gas meters for each 12,000 square feet of floor space. The final number of meter banks shall

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be at the discretion of the Company, based upon the size and layout of the particular shopping center under consideration. C

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Section 5 – MAINS

The Company has a policy of extending its main(s) to serve a new customer (or customers) provided such main extension is determined to be economically feasible. The criteria for economic feasibility shall be met when the total annual net revenue to be obtained from the customer (or customers) provides a rate of return that is equal to or greater than the overall cost of capital established in the Company's last general rate case.

The determination of the anticipated rate of return on the main extension will be based on a net present value (NPV) computation utilizing the following parameters:

1. Net revenues will be calculated by applying the applicable tariff margin rate to the estimated annual total usage and, where applicable, potential for future growth may be considered.
2. Estimated annual total usage shall be based on those appliances that will be in use during the first five (5) years of service, except as provided in paragraph 3 under "Main Extension Contract".
3. The required investment will be based upon engineering cost estimates as determined by the Company and will include the costs of all facilities required for providing service including material and labor costs associated with the installation of mains, service lines, metering and regulating equipment, easements, rights of way, street crossings, and all other required equipment or facilities.
4. The discount rate shall be equal to the overall cost of capital allowed in the Company's last general rate case adjusted for taxes and depreciation.
5. The discount period shall be equal to the economic useful life of the investment in the mains and services.
6. Main extensions producing a positive net present value at the end of the discount period shall be considered economically feasible.

Main Extension Contract

To the extent the net present value computation produces a negative result:

1. The customer shall pay to the Company an amount equal to the negative net present value at the end of the discount period, plus any additional funds required to provide for the payment of resulting taxes. This payment may be made in a lump sum or in periodic payments (without interest) -- annual, monthly, etc. C
2. If within three (3) years after the original installation, the customer making the payment adds additional major or minor appliances, the Company will refund to the customer (if paid in advance or credit his account if on extended terms), upon written request, an amount equal to the net annual revenues anticipated to be realized from the usage of the additional appliance(s).
3. In no case shall the customer making the payment be refunded more than he paid.

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The above provisions assume that only one customer will make the payments. If two or more customers make the payments, the contract will be adjusted to reflect this fact; for example, if two customers made equal payments and a refund is due because one of the two has added an additional appliance, then the entire refund shall be paid to him.

Exceptions

The Company may make exceptions to the main extension rule when system improvements are realized by the extension.

Main Relocation

If a customer requests a re-routing or relocation of a main located on a public right-of-way, the customer will be charged for this work. If the main is located on private property, such as an easement, railroad right-of-way, the case will be referred to the Engineering Department for determination as to whether a charge shall be made. The same will apply to relocations or re-routings requested by a contractor. Repairs to mains damaged by a contractor will be charged to the contractor on a "Time and Materials" basis.

Aboveground Facilities

If the above-ground facilities (such as post regulators, vent pipe, etc.) are so located that they seriously interfere with, or make impracticable, the owner's use of this property, the relocation of such facility will be done at no cost to the customer. An example of serious interference would be when the aboveground facility was located in front of a proposed narrow driveway. In all other cases, the cost of relocation will be charged to the customer. The charge, unless specified for any of the above items, will be either of the following, at the customer's option, prior to commencement of work: C

1. Estimated cost as determined by the Construction Department
2. Actual cost

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Section 6 - Rules and Regulations Governing Supply & Consumption of Gas

The consumer agrees to the following rules and regulations, having made proper application and deposit for service with the Company.

1. Consumer is responsible for damage to any gas meter or equipment belonging to the Company placed on the premises occupied by the consumer and will immediately reimburse the Company for all costs of repairing or replacing same. In accordance with Item (1), Section 1220-4-5-. 18, Reasons for Denial of Service of the Tennessee Regulatory Authority's Rules and Regulations, a consumer may be refused service if consumer has damaged the Company's equipment or tampered with the lock on a meter. The Company will charge its standard rates and charges for a broken meter lock. C
2. Consumer will use gas supplied through Company's meter only. Use of other metering devices or bypassing equipment and tampering or adjustments on company-owned metering facilities by consumer are prohibited. The Company will not permit secondary meter billing.
3. In case the meter has failed to register the quantity of gas consumed, in whole or in part, the consumer will pay such reasonable sum as is ascertained to be due for the period involved.
4. The Company's authorized agents shall have access to consumer's premises at all reasonable times for the purpose of checking, reading, servicing, and disconnecting the meter; shutting off gas; and for such other purposes as the Company may deem advisable to protect its interests.
5. The Company shall be under no duty to inspect, repair, or maintain the service of other pipes, connections, equipment, or appliances located beyond the meter outlet on the premises of the consumer.
6. The consumer shall be liable and shall pay for all gas passing through the meter until it is turned off. When termination of service is requested, consumer must ensure that the Company receives either written or verbal notice at least two business days prior to the desired date of termination. Access to the meter must be provided. C
7. The consumer is entitled to the usual discount allowed by the Company if bills are paid within the first twelve days following the date bills are rendered. All gas bills are due when rendered and they will be considered as rendered when mailed to the address specified by the consumer. A residential, head of household consumer dependent on social security or other retirement check may request a net to gross discount waiver. Qualified consumers will be granted a net to gross discount waiver and the account will be monitored for continuing compliance.
8. The Company shall have the right to shut off gas from any consumer who may be in arrears for a longer period than twenty days in paying for gas furnished hereunder or under any other prior or subsequent agreement, or for gas used by consumer at

consumer's present or any prior or subsequent address, it being understood hereby that said twenty day period commences to run from date the bill is rendered as above defined. The Company will not shut off gas for non-payment without first mailing a notice to the consumer giving him seven days to pay for the bill in arrears. The Company will not terminate service during any 24-hour period, as measured from 8:00 am on the planned date of termination, where the forecasted low temperature, as determined by the National Weather Service, is 32 degrees Farenheit or below.

9. The Company is authorized to require the consumer to make a deposit, or increase any existing deposit, in such amount as the Company deems proper for its protection before restoring gas service. The deposit amount will not exceed two consecutive billing periods or ninety (90) days, whichever is less.
10. All consumer deposits will accrue simple interest on the principal at the rate approved by the Authority. D
11. The Company will charge $55.00 during the months of February through August and $85 for the months of September through January for turning on a meter for an existing consumer or member of the same family or household at same address. This charge applies only to those consumers who have previously elected to have the meter turned off without discontinuing service or whose account has been closed because of non-payment of a bill.
12. In the event gas is shut off because of consumer's failure to pay, a charge will be made for each restoration. The Company will charge $55.00 during the months of February through August and $85 for the months of September through January plus payment of past due gas bills for turning on meters shut off for non-payment of bill. The Company will not be liable for damages for shutting off gas or for delay in restoring service. An additional deposit may also be required.
13. At the Company's option, special discounts may be offered to the approved reconnect fee to encourage customers to have their service reinstated during non-peak turn-on periods. Such special discounts will be made upon a 1 day notice to the Authority and will be available on a nondiscriminatory basis within the classifications of Sections 11 and 12 above. Notification will include the time period during which the promotion will be conducted as well as the terms and conditions of the promotion.
14. The consumer agrees to notify Company in advance of any planned change in physical premise or environment around meter or service to determine impact on safety cases, meter reading, and meter maintenance.
15. In the event the Company is unable, wholly or in part, by reason of force majeure to carry out its obligations to provide service, the obligations of the Company so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. The term "force majeure" as employed above shall mean acts of God; extreme weather conditions; strikes, lockouts, or other industrial disturbances; acts of the public enemy; war; blockades; insurrections; riots; epidemics; landslides; lightning; earthquakes; fires; storms;

floods; washouts; arrests and restraints of governments and people; civil disturbances; explosions; breakage of or accidents to machinery, lines of pipe, or the Company's peak shaving plants; freezing of wells or lines of reduction in gas pressure by its suppliers; inability to obtain rights-of-way, permits, materials, equipment, or supplies for use in the Company's peak shaving plants; and any other causes whether of the kind herein enumerated or otherwise, not within control of the Company, and which by the exercise of due diligence the Company is unable to prevent or overcome. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Company, and the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts when such course is inadvisable in the discretion of the Company.

16. When the Company in its discretion determines that it is necessary to curtail service to maintain the integrity of its distribution system or to provide for its or the public's safety, the Company shall have the right to curtail delivery of gas to any consumer.

17. In the event of a failure or interruption of service, the Company shall use all reasonable diligence to remove the cause or causes thereof, but the Company shall not be liable for any loss or damage resulting from such failure or interruption due to accidents, force majeure, extreme weather conditions, or causes beyond its control.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-86. Provide a copy of all regulatory orders supporting the deferral and rate recovery associated with the Company's request to recover deferred Pension and OPEB costs, including but not necessarily limited to the order in TRA Docket 96-00977.

RESPONSE: Please see attachment for the Order in Docket No. 96-00977.

Amortized recovery of Piedmont's previous unamortized deferred pension balances was granted in Docket Nos. 99-00994, 03-00313 and 11-00144 (Piedmont general rate cases). Please see the Company's response to Request No. 85\ for the Orders issued in Docket Nos. 99-00994, 03-00313 and 11-00144.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

February 19, 1997

RECEIVED
FEB 24 1997
STATE ATTORNEY GENERAL
CONSUMER ADVOCATE DIVISION

In Re:	)	
	)	**Docket No.**
Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges	)	**96-00977**

ORDER

This matter came before the Tennessee Regulatory Authority (hereafter "Authority") upon the petition of Nashville Gas Company (hereafter "Company" or "Nashville Gas"), an operating division of Piedmont Natural Gas Company, Inc. (hereafter "Piedmont") for a general rate increase. This matter was heard by the Authority on November 13 and 14, 1996.

I. PROCEDURAL BACKGROUND

On May 31, 1996, the Company filed a petition with the Tennessee Public Service Commission (hereafter "TPSC") requesting a general increase in its rates and charges for natural gas service and approval of certain changes to its rate schedules, classifications, and practices. On June 6, 1996, the Consumer Advocate Division, Office of the Attorney General (hereafter "Advocate"), entered a notice of appearance with the TPSC.

On July 29, 1996, pursuant to Administrative Order No. 1,[1] the Company filed its petition to recommence, and its agreement with the Advocate which stipulated that the record before the TPSC would be considered as the record before the Authority.

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[1] Effective July 1, 1996, the TPSC ceased to exist and the Authority was established. On July 18, 1996, the Authority issued its Administrative Order No. 1 in which it set forth the requirements upon which it would accept jurisdiction over any pending matters that had been brought before the TPSC and not completed prior to the TPSC's termination.

On August 27, 1996, the Authority ordered that all filings, including petitions, pre-filed testimony, petitions of intervenors, orders of the TPSC and all other matters that were filed before the TPSC with respect to the Company's request for a general rate increase be adopted as though filed with the Authority. On August 9, 1996, Associated Valley Industries group (hereafter "AVI"), a coalition of certain industrial users of natural gas, filed a petition to intervene. That petition was granted on August 20, 1996.

On September 13, 1996, a status conference was held before H. Edward Phillips, III, Associate Counsel of the Authority. On September 25, 1996, a Report and Recommendation was submitted to the Authority providing dates for the submission of any additional data requests and responses, for the filing of additional direct and rebuttal testimony and for a hearing. By Order dated October 7, 1996, the Authority adopted the procedural schedule set forth in the Report and Recommendation.

II. HEARING AND APPEARANCES

On November 13, 1996, a hearing was convened before the Directors of the Authority, at which time, the following appearances were entered by counsel:

FOR THE COMPANY:

T.G. Pappas, Esq.
Bass, Berry & Sims
2700 First American Center
Nashville, TN 37238-2700

Jerry W. Amos, Esq.
Amos & Jeffries, L.L.P.
1230 Renaissance Plaza
Greensboro, NC 27402

FOR THE ADVOCATE:

L. Vincent Williams, Esq.
Office of the Attorney General
426 - 5th Avenue, North
Nashville, TN 37243-0485

FOR AVI:

Henry Walker, Esq.
414 Union Street, Suite 1600
Boult, Cummings, Conners & Berry
Nashville, TN 37219

The Company presented testimony from Bill R. Morris, Gregory E. Aliff, Dr. Donald A. Dr. Murry, Charles W. Fleenor and John H. Maxheim. AVI presented the testimony of Donald Johnstone. The Advocate presented the testimony of Dr. Stephen N. Dr. Brown, Michael W. Warner, Daniel W. McCormac, and R. Terry Buckner.

At a regularly scheduled Authority Conference held on December 17, 1996, the Directors of the Authority, after public deliberation, announced their decision in this matter.

III. CRITERIA FOR ESTABLISHING JUST AND REASONABLE RATES

The Authority considers petitions seeking adjustments of rates and charges under Tenn. Code Ann. § 65-5-203, which requires:

> 1) that the Authority shall have the power upon written complaint, or upon its own initiative, to hear and determine whether the increase, change or alteration being sought by a public utility is just and reasonable;
>
> 2) that the burden of proof to show that the increase, change or alteration is just and reasonable shall be on the public utility making the same; and
>
> 3) in determining whether such increase, change or alteration is just and reasonable, the Authority shall take into account the safety, adequacy and efficiency or lack thereof of the service or services furnished by the public utility.

IV. TEST PERIOD

In a rate case, the Authority must, as a preliminary determination, decide which test period is appropriate. The purpose in the selection of a test period is to provide an indication of the rate of return that is likely to be produced under the existing rate structure in the reasonably foreseeable future after taking into consideration the estimated effect of reasonably expected revenues, expenses and investments.

All of the parties agreed that the Company's use of a test period from December 31, 1995, adjusted to October 31, 1997, was reasonable.

V. CONTESTED ISSUES

In its original filing, the Company requested a rate increase of $9,257,633. At the hearing, the Company agreed to reduce its request to $7,861,622[2] to reflect the fact that updated information obtained by the Company since the time of its filing required adjustments in Charitable Contributions, Operating Revenues-Forfeited Discounts, Operation and Maintenance Expenses, and Taxes Other Than Income and Retention Factor. The Advocate asserted that a rate increase was not just and that the Company should be ordered to reduce current rates by $775,415. AVI asserted that if a $4,600,000 or a $9,300,000 [3] rate increase were granted, then the industrial users should correspondingly receive either a one percent (1%) reduction in rates or a zero percent (0%) rate increase.[4] AVI's assertion is based upon its position that the Company's

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[2] See Company's Hearing Exhibit No. 5

[3] See table appearing at p. 8 of the Pre-Filed Direct Testimony of Mr. Donald Johnstone. These figures cited to in the text above represent assumed rate increases for the purpose of illustrating the portion of the increase that AVI asserted should be passed on to the industrial users.

[4] *See supra* note 2.

industrial customers are currently paying a premium for natural gas supplied by the Company, and that these rates should be competitive.[5]

V. A. Rate Base:

Rate base is the Company's net investment, which is financed through investor supplied funds, in property used and useful in providing utility service. This is the amount of investment on which the Company should be allowed the opportunity to earn a fair and reasonable rate of return. At the hearing, the disputed issues were (1) whether the Company accurately calculated accumulated depreciation and the related depreciation expense, and (2) whether the Company correctly calculated the amount of its working capital.

A. I. Accumulated Depreciation:

At the hearing, the Company's witness, Mr. Morris, testified that the Advocate's proposed calculation for accumulated depreciation contained an error,[6] which if not corrected would result in an increase in the Company's revenue requirement. Further, Morris testified that the Advocate's proposal was based on an erroneous conclusion that the Company's attrition period accumulated depreciation was overstated by two months.[7] The Advocate did not rebut the Company's assessment that its original calculation of accumulated depreciation was in error. Therefore, the Authority accepts the Company's calculation of accumulated depreciation and depreciation expense of $101,595,670 and $11,067,061 respectively based on the supporting proof, and finds that this calculation is reasonable.

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[5] To that end, AVI did not sponsor any witnesses to discuss the cost of service. Instead, AVI proffered only one witness who presented testimony on rate design.

[6] See Hearing Transcript Vol. I, p. 59, testimony of Mr. Bill Morris.

[7] See Hearing Transcript Vol. I, p. 59, testimony of Mr. Bill Morris.

A. ii. Working Capital:

The Advocate used 38 lag days for income tax expense, while the Company used a negative 106 lag days in the calculation of working capital.[8] The Company's calculation is due to its overpayment of estimated income tax liability. This overpayment and resulting refund causes the negative lag days used by the Company. The Advocate has used the forecasted tax expense included in their case to produce a positive lag day result. Whatever the reason for the overpayment, the Authority finds that it would be inappropriate to require ratepayers to fund any more for working capital relating to income tax expenses than necessary. We, therefore, adopt the 38 lag days proposed by the Advocate.

A. iii. TOTAL RATE BASE:

Adjusting Rate Base for accumulated depreciation and working capital produces a total rate base of $200,699,631. The Authority finds that this rate base is fair and reasonable and will permit the Company to earn a fair rate of return.

V. B. REVENUES & EXPENSES

The Company's current level of revenues and expenses will determine the current net income. The revenues represent dollars received from the Company's ratepayers in providing services while the expenses represent the cost of providing that same service.

B. i. Forfeited Discounts:

Forfeited Discounts are those revenues received by the Company from customers who pay their bills after the expiration of the discount period. The Company has included approximately $1,506,000 in their case for forfeited discounts while the Advocate has used

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[8] See Pre-Filed Direct Testimony of Mr. Michael Warner at p. 3.

approximately $1,417,000 which was produced by the Advocate's use of an offsetting adjustment to the Revenue Conversion Factor, discussed below.[9] At the hearing, the Company agreed with the Advocate's calculation of this item, and proposed to adjust their case accordingly.[10] Therefore, the Authority finds that approximately $1,417,000 is the appropriate amount to include for forfeited discounts.

B. ii. Allocation of Demand Cost:

The Company has proposed to allocate a portion of their fixed gas costs to the gas commodity rates. This proposal has the effect of allocating a portion of the fixed costs of purchasing gas to all customers instead of just those firm customers who use gas on the coldest days. The Company has made this proposal to recognize the principal that all customers should bear a share of the fixed cost burden. There was no opposition from any party at the hearing to this proposal.

The Authority therefore finds that the Company's proposal to allocate a portion of gas demand costs to commodity rates is reasonable and appropriate. The Company is instructed to file its future Purchased Gas Adjustments and Actual Cost Adjustments in a manner that reflects this change.

B. iii. Removal of Gas Cost from Base Rates:

This item relates to the recommendation by the Authority Staff in its compliance audit to remove gas costs from base rates.[11] The Company's current tariff rates include separate amounts for base rates which contain gas costs and a purchased gas adjustment which contains adjusted gas costs.

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[9] See Pre-Filed Testimony of Mr. Daniel McCormac at pp. 3-4.

[10] See Hearing Transcript Vol. I, p. 60, testimony of Mr. Bill Morris.

[11] See p. 13 of the Compliance Audit Report prepared by the Authority's Utility Rate Division Staff.

Since the Authority's current Purchased Gas Adjustment Rule (hereafter "PGA") allows gas utilities to "true-up" any over-recovery or under-recovery of gas costs, it is no longer necessary to consider gas costs in a rate case. Therefore, only the gross margin from gas sales should be considered in a rate case while the gas costs should be moved to the PGA calculation. This is the method approved by the TPSC for both United Cities Gas Company and Chattanooga Gas Company. Making this adjustment for Nashville Gas will create uniformity among the gas utilities regulated by the Authority and will simplify explaining (1) which components of a customer's bill we consider in a rate case and (2) which components are subject to the fluctuations of the natural gas markets. We, therefore, find that the Company should remove the gas cost from its base rates.

B. Iv. Sales Promotional Expenses:

This item represents both payroll and non-payroll expenses of Nashville Gas Company employees that perform sales promotional activities. The Company has included approximately $811,000 and $308,000 in their case for marketing payroll and non-payroll expenses respectively.[12] The Advocate has proposed to include approximately $303,000 or ($816,000 less) in marketing expenses than the Company as part of its overall adjustment for advertising expenses as discussed below. The Advocate contends that sales promotion expenses should be considered a component of advertising and, as such, should be included in the allowance for advertising.[13] Previously, the TPSC limited the Company to recover advertising expenses that were equivalent to only 0.5% of the company's gross revenues.

No party to this proceeding presented evidence that sufficiently demonstrated the TPSC ever meant to include sales promotion payroll and non-payroll expenses in the calculation of the advertising expense allowance. Further, the Advocate failed to present

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[12] See Hearing Transcript Vol. I, p.64, testimony of Mr. Bill Morris.

[13] See Pre-Filed Testimony of Mr. Terry Buckner at p. 7.

evidence that demonstrated that these expenditures were unreasonable. Finally, the Company witnesses presented credible testimony regarding the necessity and the reasonableness associated with these expenditures. Therefore, based upon the evidence presented by the Company that these expenditures were prudent and reasonable for the services rendered, the Authority finds it proper to accept the Company's calculation for Sales Promotion Expense. Further, these payroll and non-payroll expenses are not to be included in the advertising expense allowance.

B. v. Advertising Expense:

The Company has included approximately $1,486,000 in their case for advertising which represents the amount actually spent in 1995. The Company's witness Mr. Maxheim admitted that this amount was greater than what the Company was allowed to recover by the TPSC. Further, Mr. Maxheim testified that the amount of the advertising expenditures that had exceeded the amount allowed by the TPSC were paid for by the Company's shareholders.

The Company seeks recovery of the entire amount requested for this expense. However, the Advocate has proposed that the Company be limited to recover an amount for these expenditures that is equal to 0.5% of gross revenues.[14]

It is the opinion of the majority of this agency that the evidence appearing in the record demonstrates that both the shareholders and the ratepayers derive some benefit from the company's advertising expenditures. Therefore, the shareholders should bear a portion of the cost of this expense.[15] Therefore, the majority finds that the proper level of

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[14] See Pre-Filed Direct Testimony of Mr. Terry Buckner at p. 7.

[15] Chairman H. Lynn Greer voted not to approve this method of allocation for advertising expenses.

advertising expense to be allowed rate recovery shall be one-half of the amount requested by the company or approximately $743,000.

The Authority also directs its Staff to conduct a study of the appropriate allowance for advertising for all Class A gas utilities under the Authority's jurisdiction. The results of this study shall be reported to the Authority no later that May 31, 1997.

B. vi. Payroll Expenses:

Three issues were raised in this case regarding payroll expenses. These issues dealt with what should be the appropriate amounts allowed for the following expenses: corporate office payroll allocated from North Carolina to Tennessee operations, Tennessee Direct payroll, and the Company's Long Term Incentive Plan.

a) Corporate Allocated Payroll:

The first issue concerns the proper allocation of corporate payroll expenses from Piedmont's corporate office in North Carolina to Tennessee. During 1995, the Company consolidated some of its functions into Piedmont's corporate office in North Carolina. This consolidation replaced both payroll and non-payroll expenses that were historically associated with Tennessee. Now these expenses will be allocated to Nashville from the corporate office.[16] Although the Company made this consolidation in 1995, no expense was allocated to Tennessee until November 1, 1996, which coincides with the beginning of Piedmont's fiscal year. Prior to this time, this expense was allocated only to the Company's operations in North and South Carolina.

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[16] See Hearing Transcript Vol. I, pp. 88-89, testimony of Mr. Bill Morris.

The Company has included $2,440,000 in allocated corporate wages in their rate case for this item.[17] This amount represents the allocation of those corporate employees who provide services to Tennessee.

The Advocate seeks to have the Authority approve the 1995 Tennessee payroll expenses[18] that did not reflect the direct or allocated expense changes that had actually occurred. The Advocate's position is inappropriate because it does not recognize the attrition period consolidation as a known and measurable occurrence. Therefore, the Authority finds that the Company's calculation of $2,440,000 in allocated corporate wages is just and appropriate.

b) Direct Payroll:

The second payroll issue relates to what is the proper amount of Tennessee direct payroll expenses. The Company has included $11,694,000 in their case for direct salaries & wages while the Advocate has only included $11,388,000 for a difference of $306,000. In this case, the Company has used the employee level at December 31, 1995, while the Advocate used the employee level as of August 31, 1996.[19] The total number of employees declined during 1996 due to consolidations of work functions between the Nashville and North Carolina offices. As a result, the Advocate was able to capture a lower employee level which produces the lower expense for the attrition period.

After careful consideration of the evidence in the record, the Authority finds that it is appropriate and reasonable to reduce the Company's Tennessee direct payroll expenses to $11,388,000. This reduction reflects the fact that the Company has reduced its number of employees since the filing of this case, and that this reduction of employees should be

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[17] See Pre-Filed Rebuttal Testimony of Mr. Bill Morris at p. 14.

[18] See Pre-Filed Direct Testimony of Mr. Terry Buckner at pp. 10-11.

[19] See Pre-Filed Direct Testimony of Mr. Terry Buckner at p. 6.

reflected in the Authority's decision. Therefore, the Company's original filing is reduced by $306,000 for direct salaries & wages.

c) Long Term Incentive Plan:

The third payroll issue is the Long-Term Incentive Plan (LTIP) for upper management employees. The LTIP program is designed to provide additional compensation for top executives that achieve preset financial targets established by the Company. The Company has included approximately $600,000 in their rate request for LTIP while the Advocate has excluded the entire amount from its case.[20]

There was a great deal of testimony presented on this issue at the hearing. At issue here is whether funding for the LTIP should come from the ratepayers or from the company's shareholders through savings brought about by the plan. The record reflects the fact that both North and South Carolina permit the shareholders and ratepayers to share this expense at a ratio of twenty-five percent (25%) to seventy-five percent (75%) respectively. However, after much consideration, the majority finds that both the shareholders and ratepayers equally share in the benefits derived from the LTIP. Therefore, the majority finds that both the shareholders and ratepayers should fund the LTIP on a fifty-fifty percentage (50/50) ratio. Accordingly, the Company's original filing is reduced by approximately $300,000.[21]

B. vii. Injuries and Damages Expense:

Injuries and damages expense relates to premiums the Company pays for various

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[20] See Pre-Filed Direct Testimony of Mr. Terry Buckner at pp. 11-12.

[21] Director Sara Kyle voted not to approve the allocation for this expense. See p. 105 of the December 17, 1996, Authority Conference Transcript.

liability insurance policies such as Fire Protection, Directors & Officers Liability, Automobile coverage, and their self-insured program for Worker's Compensation coverage. While the forecast for Worker's Compensation is based on an independent estimate from an outside actuary, the amounts for the remaining items are based on Company estimates.

The Company originally included approximately $967,000 in its case for injuries and damages expense. At the hearing, the Company reduced its request for this item to approximately $725,000 because of an error in their calculation of Worker's Compensation Insurance.[22] The error is worth approximately $240,000 as indicated in the Company's hearing exhibit.

The Advocate has included $650,000 in their calculation of injuries and damages expense. To calculate this expense the Advocate used an overall growth factor of 12.66% [23]to forecast the change in this expense. The Advocate has provided more justification for the use of this growth factor than the Company has for its own. The Authority, therefore, finds that the Advocate's calculation of $650,000 for Injuries & Damages expense is reasonable and appropriate.

B. viii. Pension Expense:

The Company originally included approximately $1,300,000 of net pension expense in its filing. This amount represents the expense that the Company plans to report in its financial statements during the next year. At the hearing, the Company lowered this amount to approximately $900,000.[24]

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[22] See Hearing Transcript Vol. I, pp. 80-81, testimony of Mr. Bill Morris.

[23] See Pre-Filed Direct Testimony of Mr. Terry Buckner at p. 4.

[24] See Hearing Transcript Vol. I, p. 88, testimony of Mr. Bill Morris.

The Advocate proposes that the pension expense be excluded from the Company's request. The Advocate correctly demonstrated that the Company's plan is fully funded, and no contribution is necessary at this time.[25] For this reason, the Authority finds that to appropriately match the Company's current pension expense with its current ratepayers, the minimum required contribution should be adopted as the current pension expense.[26] Since the pension plan is fully funded, the Company's minimum required contribution for this case is zero dollars ($0.00), therefore the Authority adopts this dollar amount for the Company's pension expense.

The Advocate has further excluded approximately $350,000 in pension fund administrative costs. The administrative cost that the Advocate seeks to exclude, encompasses, but is not limited to the following fees, actuarial fees, investment manager fees, trustee fees, and audit fees. The Authority finds that the Company should recover the $350,000 in pension fund administrative costs, since this is a continuing prudent cost of the Company. Further, the Authority will permit the Company to establish a deferred asset for the difference between the amount of Pension expense funded, and the amount expensed on the Company's books.

B. Ix. <u>Allocation of Corporate Office Expenses:</u>

Since Piedmont operates in three states, it is necessary to allocate corporate expenses to each jurisdiction. Historically, these joint expenses have been allocated on the percentage of net plant in Tennessee to total net plant. This same allocation method, which is updated annually, is also used in the company's other jurisdictions outside Tennessee.

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[25] See Pre-Filed Direct Testimony of Mr. Terry Buckner at pp. 8-9.

[26] See December 17, 1996, Authority Conference Transcript at p. 79.

The Advocate has applied an allocation factor based on Tennessee customers to total company customers.[27] The Advocate's rationale for allocating corporate expenses on customers instead of net plant is that the TPSC has used the customer allocation method in relation to other regulated gas utilities.

The Authority recognized that the TPSC has historically allowed Piedmont to allocate corporate office expenses to Tennessee ratepayers by the net plant allocation method. The basis for the applications of the net plant allocation method to Piedmont is not simply based upon the historical practices of the TPSC. Rather, evidence exists that demonstrates that Piedmont is permitted to use the net plant allocation method in both North and South Carolina, which are the other two jurisdictions in which Piedmont provides service. Therefore, the Authority should provide consistency in the application of the new plant allocation method between the jurisdictions. Moreover, consistency of treatment between the jurisdictions will prevent Piedmont from recovering more or less than one hundred percent (100%) of its prudently incurred corporate office expenses.[28] Therefore, it is for these reasons that the Authority finds that the Company's net plant allocation methodology is acceptable.

B. x. <u>Forecasting of Attrition Period Expenses:</u>

This issue has been separated into two categories and pertains to the differences between the Company and the Advocate's approaches in arriving at forecasted attrition period expenses that were not manually priced-out. The Advocate has reduced the Company's request by approximately $748,000 for these items. The Company has used a zero-based calculation on most of their expenses, while the Advocate chose to apply a growth factor based on the Gross Domestic Product (hereafter "GDP") to the entire amount.

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[27] See Pre-Filed Direct Testimony of Mr. Terry Buckner at pp. 10-11.

[28] See Hearing Transcript Vol. I, p. 63, testimony of Mr. Bill Morris.

For the items that were not calculated on a zero-based method, the Company grew these amounts by a factor based on the Consumer Price Index (hereafter "CPI").

a) CPI vs. GDP Growth:

Of the $748,000 total reduction for this item, approximately $113,000 relates to the Company using a CPI growth factor[29] while the Advocate has used a GDP growth rate.[30] The CPI index relates to price changes in consumer goods, while the GDP index relates to the price changes for the entire economy. Since the expenses that are applied to a growth rate are not limited to consumer type items, the Authority is persuaded that the Advocate's use of the GDP index is more precise. For this reason, the Authority finds that the use of the GDP index is appropriate and that the company's request should be reduced by $113,000 to reflect this adjustment.

b) Zero-Based Items:

As stated above, the Advocate has applied their GDP growth rate to this entire amount, while the Company has chosen to price these amounts out separately. Of the $748,000 total proposed reduction for this item by the Advocate, approximately $635,000 relates to the different methods of calculation described above. Generally, it is preferable to price-out these expenses rather than apply a broad growth rate when possible. For this reason, the Authority finds that it shall accept the Company's method of zero-based calculation for these expenses.

The combination of these two items results in a net decrease of $113,000 from the Company's filing.

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[29] See Pre-Filed Rebuttal Testimony of Mr. Bill Morris at pp. 8-11.

[30] See Pre-Filed Direct Testimony of Mr. Terry Buckner at pp. 3-6.

B. xi **Charitable Contributions:**

The Company originally proposed to recover certain charitable contributions in its rates. At the hearing, however, the Company agreed to remove this item as an issue and therefore exclude charitable contributions from their case.[31] Therefore the Authority finds that the company shall reduce its request by approximately $96,000.

B. xii. **Non-Recurring Expenses:**

Generally, non-recurring expenses are material expenditures made during the test period that are not likely, or expected to re-occur during the forecasted attrition period. In his pre-filed direct testimony, Advocate witness Buckner testified that he deducted approximately $145,000 of expenses that were described as non-recurring expenses.[32]

As part of an effort to allow the hearing to be completed on November 14, 1996, the Company and the Advocate reached an agreement that permitted the Advocate to enter all of the pre-filed testimony of Daniel McCormac, Terry Buckner and Mike Warner into the record while the Company waived cross-examination. However, both McCormac and Buckner were permitted to address matters raised during the hearing which were not addressed in their pre-filed testimony.

Thus, because of this agreement, the Company did not pose questions to Buckner that related to the nature of specific non-recurring expenses. However, despite the fact that no break-down is provided as to what specific expenses generate the full amount of the non-recurring expenditures, the Authority finds that is reasonable to expect a utility such as Nashville Gas to make certain expenditures that are non-recurring. Further, it is unreasonable to expect that the Company would have zero non-recurring expenses. The

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[31] See Hearing Transcript Vol. II at p. 133, testimony of Mr. John Maxheim.

[32] See Pre-Filed Direct Testimony of Mr. Terry Buckner at p. 6.

Company has not provided an alternative figure to the one proposed by the Advocate, neither has the Company denied that it had non-recurring expenses for the attrition period. The Authority finds that the Advocate has proposed a reasonable reduction for the Company's non-recurring expenses. Therefore, the Authority finds that the Company shall reduce its request by approximately $145,000.

B. xiii. **Administrative Transferred Credit:**

Transferred Credits are accounting mechanisms used to allocate a portion of the Company's overhead expenses to construction costs and non-utility operations. As a result, the amount for transferred credits will either increase or decrease with corresponding changes in overhead expenses. Examples of overhead expenses that effect transferred credits include administrative employees salaries (both Corporate & Tennessee), pension expense, 401(k) expense, all insurance coverage, and miscellaneous employee benefits expense.

The Company has included approximately $1,306,000 in their case for transferred credits while the Advocate has included $1,487,000. According to the Advocate, the Company's figure contained an error of approximately $424,000.

At the hearing, the Company agreed with the Advocate that their original calculations were in error.[33] However, the Company contends that the actual effect of the error is approximately $484,000 and they have adjusted their case accordingly. The Advocate presented no objections to this revised calculation. Therefore, the Authority finds that the correct adjustment should be $484,000.

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[33] See Hearing Transcript Vol. I, pp. 82-83, testimony of Mr. Bill Morris.

B. xiv. Employee Benefits Expense:

The Company has included expenses for country club dues, and fees for professional sports tickets and suites in the above-the-line utility operations. While these amounts were removed for rate case purposes, they still should not be booked as utility operating expenses. Therefore, the Authority finds and directs the Company to begin accounting for these expenses to a non-utility account.

VI. COST OF CAPITAL

The Authority in reaching a decision on a rate of return must give in-depth analysis and consideration to numerous factors, such as capital structure, cost of capital, and changes that can be reasonably anticipated in the foreseeable future.

VI. A. Capital Structure:

Company witness Dr. Murry proposes using the following capital structure based on the period ending October 31, 1997: 46.68% long term debt, 1.52% short term debt and 51.80% common stock equity. Alternatively, Advocate witness Dr. Brown suggests using the Company's 1995 capital structure of 48.8% long term debt, 1.60% short term debt and 49.6% common stock equity.

We find that the capital structure proffered by the Advocate is appropriate in this case. The Advocate's recommendation is based on verifiable and reasonably current data. Conversely, the suggested capital structure proposed by Company witness Dr. Murry is based on speculation for which he provides no convincing foundation. The table below summarizes the recommended capital structures.

	Long Term Debt	Short Term Debt	Equity
*NGC	46.68%	1.52%	51.8%
**CAD	48.80%	1.60%	49.6%

* The abbreviation "NGC" used in this table refers to Nashville Gas Company.
** The abbreviation "CAD" used in this table refers to the Consumer Advocate.

VI. B. Cost of Debt:

There is no disagreement between the parties concerning the cost of long-term and short-term debt; therefore, it is appropriate to use the cost rates put forth by both parties: 8.32% for long-term debt and 5.92% for short-term debt.

VI. C. Return on Equity:

Company witness Dr. Murry estimated the Company's cost of equity primarily using the Discounted Cash Flow (DCF) method, the Risk Premium method and the Capital Asset Pricing Model (CAPM). Dr. Murry's DCF estimates range from 9.31% to 15.19%.[34] His risk premium estimate is 13.21% using historical data and 12.97% using current data. His CAPM estimate was 13.12%. In his direct testimony, Dr. Murry recommends allowing a return on common equity between 13.00% and 13.25%. However, in his oral testimony Dr. Murry favors the lower bound of this range based on current market conditions. Advocate witness Dr. Brown uses two techniques to estimate the Company's cost of equity, the DCF and Risk Premium methods. These methods yield estimates of 11.48% and 10.64%, respectively. Dr. Brown recommends allowing a return on common equity of 11.00% based upon a monthly compounding of earnings.

Dr. Brown testified extensively that the approved cost of equity should be adjusted for monthly compounding of earnings. The Authority finds this adjustment inappropriate

[34] Actually, Dr. Murry's DCF estimate was of the overall cost of capital, from which a cost of equity estimate can be imputed.

because it assumes a constant monthly earnings rate not typical of a gas utility.[35] Further, this adjustment ignores variable dividend payments, and conflicts with the calculation of annual earnings elsewhere in this case. Finally, Dr. Brown did not produce any evidence that this theory has been applied in any other case. Therefore, the Authority finds that this theory is inappropriate for use in this rate case.

Dr. Murry testified to several criticisms of Dr. Brown's Risk Premium analysis of the cost of equity. However, Dr. Murry's most important criticism was that Dr. Brown inappropriately combines an estimated short term market risk premium with an estimated long term debt yield.[36] The Authority finds that Dr. Brown's use of inputs based on inconsistent time horizons is inappropriate.

Dr. Brown focuses his criticism on Dr. Murry's Risk Premium analyses using both historical and current data as well as his Comparable Earnings analysis. Dr. Murry uses the results of the latter only as a qualitative check on his other estimates. For all of these analyses, Dr. Brown alleges that Dr. Murry unjustifiably and inappropriately compares the Company to dissimilar firms. In addition to his criticisms of Dr. Murry's methodology, Dr. Brown argues that the approved cost of equity should be adjusted for monthly compounding which gives the Company an opportunity to earn more than the allowed annual rate.

After careful consideration of the testimony of both witnesses, and the evidence in the record, the Authority finds that the cost of equity is 11.50%. Moreover, the cost of equity being adopted by the Authority herein is within the range of DCF calculations proposed by both Dr. Murry and Dr. Brown.

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[35] See Pre-Filed Rebuttal Testimony of Dr. Donald A. Murry at p. 7

[36] See Pre-Filed Rebuttal Testimony of Dr. Donald A. Murry at p. 8.

VI. D. Overall Cost of Capital:

Based on the approved capital structure which consists of 48.8% long-term debt, 1.60% short term debt and 49.6% common stock equity the Authority approves an overall rate of return of 9.85%.

VII. RATE INCREASE

After determining the appropriate Rate Base, Operating Income, and Fair Rate of Return, we can now calculate the appropriate revenue level and determine how much rates should be adjusted. Since the parties have agreed that the revenue conversion factor of 1.626747 as proposed by the Advocate is appropriate for this case, we will also use this to determine any rate adjustment.

Based on the findings and conclusions set forth above, the Authority concludes that the just and reasonable revenues, expenses, and rate base produce a rate increase of $4,417,290. The Authority further concludes that in order to permit the Company to earn the return determined to be just and reasonable, the Company should be allowed to increase its rates by $4,417,290. Further, a majority of the Authority has determined that this rate increase be effective beginning with service rendered on and after January 1, 1997.[37]

VIII. RATE DESIGN AND TARIFF CHANGES

Company witness Mr. Fleenor testified that he designed the Company's proposed rates using a cost of service study of existing rates along with traditional rate design principles and the desire to provide additional services to the ratepayers. The traditional rate design principles considered by Mr. Fleenor included (1) value of service, (2) the need

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[37] Director Sara Kyle moved that the increase become effective on January 28, 1997. This motion failed for lack of a second, and as a result, the majority concluded that the increase would become effective on January 1, 1997. See December 17, 1996, Authority Conference Transcript at p. 115.

to avoid discrimination among classes of service, (3) system load equalization and (4) revenue stability. Mr. Fleenor also considered several non-economic factors. He testified that the main objective of his rate design was to continue to develop a design and structure that will enable the Company to continue to adapt to the many changes occurring in the natural gas industry and to recommend rate levels that more properly reflect cost and value of service. Based on the Company's rate design considerations and its original request to increase its rates by $9,257,633, the Company proposed to increase rates to the residential category by 9.3%, to the small commercial class by 5.3% and to the large commercial and industrial class by 2%.

The Advocate's witness Mr. McCormac did not recommend how a rate increase should be applied, however, he did suggest that any change in rates be spread equally among all customer classes.[38] AVI's witness Mr. Johnstone strongly advocated cost-based rates, and as a result proposed that there should be no increase in industrial rates. Finally, he suggested that if the full requested increase were not granted, then the industrial rates should be reduced by one percent (1%).[39]

After careful consideration of the testimony and exhibits of the parties, the Authority finds that the rate increase approved herein should be spread equally to all customers. It is the intent of the Authority to spread this increase to all ratepayers, including Interruptible Sales customers, Transportation customers, and Special Contract customers, in order to minimize the overall impact of this rate change. In addition, the Authority concludes that the residential customer charge should be increased from $6.00 per month to $7.00 per month.

The Company also proposed certain changes to its tariff language to permit the Company to respond to existing competitive conditions under FERC Order No. 636. Among other things, these changes include provisions for customers to elect sales or

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[38] The Advocate proposed a decrease in rates of $775, 415.

[39] See Pre-Filed Direct Testimony of Mr. Donald Johnstone at p.8.

transportation service on an annual basis so that these customers will be prevented from switching back and forth as the price of spot gas and the price of gas under the Company's PGA varies from month to month. No party has objected to these provisions and the Authority finds them to be fair and reasonable. Therefore, the Company is instructed to take the appropriate action so the implementation of these provisions may not be unnecessarily delayed.

IX. DISPOSITION OF PROCEDURAL MOTIONS

The parties to the proceeding filed several motions concerning certain procedural issues. On November 12, 1996, the Company filed its Motion to Strike the Rebuttal Testimony of Advocate witness Dr. Stephen Brown. After hearing oral argument on this matter, the Authority denied the motion. The Authority noted that the Company would not be unduly prejudiced by the admission of the testimony, because the Company would have the opportunity to cross-examine the witness, attempt to impeach the witness and object to portions of the witness' testimony.

On November 13, 1996, the Advocate filed a Motion requesting disclosure of documents and records prepared by the Authority Staff in relation to this proceeding. The Directors of the authority permitted the Advocate to present oral argument. After careful consideration, the Authority denied the Advocate's motion. In denying the motion, the Authority asserted the deliberative privilege which protects the confidentiality of communication between a Director and certain staff members.

Finally, the Advocate made an oral motion for a one day continuance of the proceeding. The Advocate stated that late filed discovery responses by the Company warranted such continuance. After presentation of oral argument by the parties, the Authority denied the motion.

IT IS THEREFORE ORDERED:

(1) That the rates filed by Nashville Gas Company on May 31, 1996, are hereby denied;

(2) The Company is directed to file tariffs with the Authority that are designed to produce $4,417,290 in additional revenue, for service rendered on and after January 1, 1997, and any other tariffs necessary to be consistent with this Order;

(3) In future true-ups under its Purchase Gas Adjustment (PGA), the Company shall use the demand allocation percentages;

(4) That the residential customer charge shall be increased from $6.00 per month to $7.00 per month;

(5) That the Authority Staff shall conduct a study of the appropriate allowance for advertising for all Class A gas utilities under the Authority's jurisdiction. The results of this study shall be reported to the Authority no later that May 31, 1997;

(6) That the Company shall begin accounting for employee benefit expenses in a non-utility account;

(7) That the Company shall establish a deferred asset for the difference between the amount of Pension expense funded, and the amount expensed on the Company's books;

(8) That the Company shall exclude gas costs from its base rates, and shall instead file an appropriate Purchased Gas Adjustment to reflect all of its gas costs;

(9) Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from and after the date of this Order; and

(10) Any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Division, within sixty (60) days from and after the date of this Order.

CHAIRMAN

DIRECTOR

DIRECTOR

ATTEST:

EXECUTIVE SECRETARY

ORD/96-00977

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1-87. Regarding the recovery of deferred environmental costs, respond to the following:

a. Has the Company investigated the extent to which legacy insurance policies were in place which would provide reimbursement, or the possibility of cost reimbursement associated with these environmental costs?

b. If such legacy insurance investigation has occurred provide copies of all documentation retained regarding that investigation, including copies of relevant legacy insurance policies.

c. If the Company has obtained any insurance reimbursements of its costs since January 1, 2011 provide the annual amount of such recovery and identify how such cost recovery has been recorded on its books and records.

d. If the Company has not investigated the extent to which legacy insurance policies were in place which may provide reimbursement, provide all justification for recovery of such costs when all avenues of insurance reimbursement have not been pursued.

RESPONSE:

a. The Company has not identified any legacy insurance policies that would provide for cost reimbursement associated with the deferred environmental expenses included for recovery in this proceeding.

b. Piedmont has not identified any relevant insurance policies.

c. Piedmont has not obtained any such insurance reimbursements.

d. The Company has not identified any legacy insurance policies that would provide for cost reimbursement associated with the deferred environmental expenses included for recovery in this proceeding.

Name and Title of Preparer: Arnold Garcia, Director - Insurance

Name and Title of Responsible Person: Arnold Garcia, Director - Insurance

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

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1-88. Regarding the Company's inclusion of Hedging Open Positions within its Working Capital balance within tab D within the 'WorkingCapital_Adj' file respond to the following:

a. Provide a comprehensive explanation of the Company's accounting for hedging transactions including how such gains and losses from hedging activity are recorded.

b. Identify the monthly hedging costs, gains and losses recorded in 2019 by account.

c. Indicate whether hedging gains and losses are recoverable from ratepayers through the Company's purchased gas mechanism or related mechanism.

d. Confirm that hedging costs are included within the ACA mechanism and such costs are recovered in fully from ratepayers.

e. Refer to the TPUC Staff report issued February 22, 2019 and indicate whether hedging gains and losses are reflected within the identified Gas Procurement Mechanism Gains/Losses of $549,154.

f. Provide a comprehensive explanation justifying the inclusion of this account within Rate Base.

RESPONSE:

a. • Hedge contracts purchased are a debit to account 182963 (TN Hedging Open Positions) and accounts payable is credited.

• Hedge contracts that have expired are removed from account 182963 (TN Hedging Open Positions) with a credit and a debit to 253142 (ACA - Nashville Gas Purchases)

• At month end the cost of open options is credited to account 253140 (TN ACA Hedging-Contra) and debited to 175001 (Deriv Assets). The gain is credited (loss debited) to 253211 (Deferred M/M Gain Loss) and offset to account 175001 (Deriv Assets).

b. See attachment.

c. Hedging costs and resulting gains or losses are reclassed from the hedging account (A/C 0182963) to the ACA Deferred account (A/C 0253142) as they expire or are exercised. Until they are expire or are exercised, the open positions remain in A/C 182963.

d. Hedging costs and resulting gains or losses are reclassed from the hedging account (A/C 0182963) to the ACA Deferred account (A/C 0253142) as they expire or are exercised. Until they are expire or are exercised, the open positions remain in A/C 182963.

e. No, hedging gains/losses are not reflected in the Gas Procurement Mechanism Gains/Losses.

f. Open hedging positions are not included in the deferred account and therefore not reflected in the Gas Procurement Mechanism Gains/Losses until they expire. The hedging plan allows for hedges to be made on a 12-month time horizon so hedges could theoretically be open for 12 months before they expire. In essence, Piedmont has paid for the hedging options which has been deemed to be a recoverable expense but does not recover it until it expires.

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Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-89. Provide all available evidence documenting that the Deferred Pension Asset identified within tab "D" within the "WorkingCapital_Adj" file is in compliance with the February 19, 1997 Docket No. 96-00977 order referenced in Ms. Bowman's testimony, for each year in which such deferred balance was accumulated. Such documentation should clearly indicate the reference as to the nature of the pension 'cost' being deferred, whether it represents pension funding, GAAP expense or some other aspect of pension cost.

RESPONSE: Please see the Company's response to MFR Item 12 for Excel workpaper "5C_Pension Adj", Tab <1> Summary. This workpaper provides a rollforward of the 2011 TN Deferred Pension balance as approved in Docket No. 11-00144 to the end of the test period on March 31, 2020.

The costs that were deferred were funding amounts -- the TN portion of the Company's contributions to the pension plan -- in the period of time since the last general rate case.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

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1-90. Provide a copy of the February 19, 1997 Order in Docket No. 96-00977 referenced in Ms. Bowman's testimony.

RESPONSE: Please see the Company's response to Request No. 86.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-91. Provide copies of the Commission orders in Docket Nos. 99-00994 and 03-00313 as referenced in the testimony of Ms. Bowman.

RESPONSE: Please see the Company's response to Request No. 85.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-92. Regarding tax collections payable, indicate whether such balances were included within the Cash Working Capital study or otherwise used to reduce Rate Base? If not, provide the rationale for not including such balances within the determination of Rate Base.

RESPONSE: Tax collections payable were not considered in past lead lag studies by Piedmont and were not considered in the current lead lag study.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-93. Provide the monthly PNG Balance Sheets in the format provided within MFR 11 for the period January 2019 – the most current balance sheet available. Provide updates as new information becomes available.

RESPONSE: See attachment.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-94. For each item listed as Per Books Test Period contained within the Summary tab within the Revenue requirement Summary file, identify the accounts and balances which roll-up into the totals.

RESPONSE: See attachment.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-95. Regarding the initial pleading filed by the Company in Docket No. 16-0006, the Company expressed to the Commission that "As that process (integration) moves forward, Piedmont and Duke Energy anticipate that the benefits of the merger will be further defined and quantified." With respect to this statement, provide any information provided to the Commission or the Commission Staff after making this statement, which defines or quantifies the benefits of the merger.

RESPONSE: Information supportive of merger benefits was provided to the TPUC in Piedmont's application in Docket No. 16-0006 filed January 15, 2016, specifically, in Exhibit E of that filing. Further, Piedmont Witness Sasha Weintraub's prefiled direct testimony in Docket No. 20-00086, filed July 2, 2020, listed merger benefits at Page 9, Line 17 through Page 10, Line 17.

Name and Title of Preparer: Bruce Barkley, VP - Rates and Natural Gas Supply

Name and Title of Responsible Person: Bruce Barkley, VP - Rates and Natural Gas Supply

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-96. Provide the monthly supporting balances by account (account number and name) which are relied upon to input the value for Accumulated Deferred Income Taxes, entered as a hard-coded number on cell F50 within the Summary tab of the Revenue Requirement Summary file.

RESPONSE: See attachment.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-97. Refer to the PNG Balance Sheet – 2019 within MFR 11. Confirm whether balances associated with the following accounts are included within Rate Base:

a. 019001 ADIT Prepaid Federal Taxes

b. 0190002 ADIT Prepaid State Taxes

c. 0283100 ADIT Other Federal Taxes

d. 0283101 ADIT Other State Taxes

If such balances are incorporated within Rate Base, provide the monthly balances for these accounts for the period January 2018 – current.

RESPONSE: These four accounts were included in Rate Base as a part of Accumulated Deferred Income Taxes. Please see the Company's response to Request No. 96 which details the accounts included in ADIT.

See the attachment herein for the monthly balances of these four accounts from January 2018 to June 2020.

Name and Title of Preparer: Jenny Furr, Rates and Regulatory Strategy Manager

Name and Title of Responsible Person: Quynh Bowman, Director Rates and Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-98. Provide a comprehensive description of the nature of transaction giving rise to account i) 019001 ADIT Prepaid Federal Taxes and ii) 0190002 ADIT Prepaid State Taxes.

RESPONSE: FERC Accounts 190, 282, and 283 capture all ADIT balances. 0190001 ADIT Prepaid Federal Taxes and 0190002 ADIT Prepaid State Taxes capture the portion of ADIT balances, specifically Deferred Tax Assets that are not related to Property Plant & Equipment.

A deferred tax is an item that results from tax authorities recognizing revenue or expenses at a different time than that of the book accounting standards. In the case of a deferred tax asset, this timing difference results in an acceleration of taxable income, acceleration of a book deduction or tax due and therefore a tax liability earlier for tax when compared to book.

Name and Title of Preparers: Chris Nelson, Tax Services Manager; Brian Neiheisel, Senior Tax Services Manager

Name and Title of Responsible Person: John Panizza, Director - Tax Operations

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-99. For the following accounts provide a reconciliation of the book/tax timing differences which comprise the December 31, 2019 balances:

a. 019001 ADIT Prepaid Federal Taxes

b. 0190002 ADIT Prepaid State Taxes

c. 0283100 ADIT Other Federal Taxes

d. 0283101 ADIT Other State Taxes

e. 0282100 ADIT Property Plant and Equipment – Federal Taxes

f. 0282101 ADIT Property Plant and Equipment – State Taxes

RESPONSE: See Attachment.

Name and Title of Preparers: Chris Nelson, Tax Services Manager; Brian Neiheisel, Senior Tax Services Manager

Name and Title of Responsible Person: John Panizza, Director - Tax Operations

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

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1-100. Confirm whether the Company has included ADIT balances associated with common plant in service allocated to Tennessee within its proposed Rate Base computation. If such ADIT balances are not allocated to PNG TN rate base, provide the rationale for such exclusion.

RESPONSE: Yes, Piedmont has included ADIT balances associated with its common plant in service allocated to Tennessee.

Name and Title of Preparer: Chris Nelson, Tax Services Manager; Brian Neiheisel, Senior Tax Services Manager

Name and Title of Responsible Person: John Panizza, Director - Tax Operations

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

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1-101. Refer to Tab 'F' Provide a comprehensive definition for each item referenced within rows 10 and 11 within this spreadsheet giving rise to the $19.5 million rate base component, including an explanation of the types of transactions/calculation underlying the account balances. For each account listed identify whether such balances are reflected of cash or accrual computations and if accrual provide the rationale for inclusion as a Rate Base component.

RESPONSE: Please see attachment.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-102. Provide a comprehensive explanation justifying inclusion of AFUDC and CWIP in the revenue requirement from: i) a regulatory theory perspective and ii) any applicable legal requirements the Company believes dictate above the line treatment of these items.

RESPONSE: The inclusion of CWIP and AFUDC in rate base has been an accepted practice by this Commission in the past.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-103. Refer to the tab PNG Balance Sheet – March 2020 within MFR 11. Provide a matrix indicating the assignment of the of the March balance of $240,640,598 within account 106 Completed Construction Not Classified, to specific Plant accounts for purposes of determining appropriate levels of Depreciation Expense to reflect within this case. Provide an explanation of how such account classifications were determined.

RESPONSE: See attachment. Prior to unitization, project charges are generally allocated to specific plant accounts in alignment with the total project cost estimate by plant account.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-104. Refer to the tabs PNG Balance Sheet – 2019 and PNG Bal Sheet March 2020 within MFR 11, specifically to the balances in Account 106 within each respective Balance Sheet. Please respond to the following questions:

a. The March 2020 balance (TN) of this account declined approximately $60 million from the balance at the end of December. Provide a comprehensive explanation of the information that became available to Piedmont which permitted the classification of this large balance within this ninety-day period and how it can assure the Commission of the accuracy of the accounting entries giving rise to the sharp decline in the balance of this account.

b. With respect to the $301 million balance at December 31, 2020 segregate the amounts by the year in which the underlying projects were deemed to be 'in service' and initially charged to account 106.

c. Provide a comprehensive explanation of what prevents the Company from working down this balance to levels representing 90 – 180 days of capital expenditures?

d. Provide copies of all due diligence information prepared or identified by Duke relative its review Piedmont's balances of Account 106 prior to its acquisition of Piedmont.

e. Provide copies of all Piedmont/Duke internal auditor reports which discuss in any way the relative balances of Account 106 issued during the period January 1, 2018 through July 31, 2020.

RESPONSE:

a. The decrease in the Account 106 balance from December of 2019 to March of 2020 is the result of capital project unitization efforts by the Company's asset accounting personnel. Capital project unitization transfers project costs from Account 106 to Account 101 once a project has been completed and all known and anticipated costs have been incurred and applied to the project. Much of the research that needed to be done in order to unitize the projects associated with this $60 million decrease was done prior to December 2019. Approximately half of the $60 million decrease was for a blanket project containing several years of service assets.

It is the responsibility of the project owner/manager to provide accurate estimates, identify and quantify property units installed or removed, identify the asset location, review project charges for appropriateness, and provide supporting details in order to categorize project charges by FERC utility account.

The Company's asset accounting personnel perform a high-level standard review for reasonableness by project prior to executing the unitization process. This is accomplished using system validations called Automatic Review for Closing (ARC) Rules, which are PowerPlan business rules used to validate whether updates or changes are need for the project to be unitized. Asset accounting addresses ARC failures prior to unitizing projects.

b. See attachment.

c. The Company strives to maintain timely project unitizations, while at the same time reducing the unitization backlog on older projects as quickly as reasonably possible. Timely is characterized as "completing" capital projects (e.g. receiving and paying

all project charges/invoices) within 6 months of the project in-service date; the unitization work begins upon project completion, with a timely goal of completing unitizations within 6 months of the project completion date.

The timeliness of unitization is affected by the divided focus of personnel to resolve the unitization backlog while simultaneously striving to keep the current projects unitized timely. In 2020, the pace of unitization is 34 projects per month for Tennessee projects, which outpaces the number of new projects added by almost double. Therefore, the pace of unitization is more than adequate to ensure timely unitization once the backlog is completely unitized.

d. No Duke due diligence information regarding Piedmont's Account 106 balances was identified.

e. The Internal Audit Department of Duke Energy Corporation has not conducted any audits related to Piedmont's account 106 balance between January 1, 2018 and July 31, 2020, therefore, there are no responsive documents to this request.

Name and Title of Preparer:

a., b., c. Nefertiti Collins, Supv - Project Accounting

d. Doug Templeton, Rates & Regulatory Strategy Analyst

e. Todd Yaeger, Director - Customer and Corporate Audits

Name and Title of Responsible Person:

a., b., c. Linda Miller, Manager - Accounting II

d. Pia Powers, Managing Director - Gas Rates & Regulatory

e. Todd Yaeger, Director - Customer and Corporate Audits

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-105. Refer to the Confidential response to MFR 55 for 2019. Provide a thorough summary describing the variance between actual and budgeted capital expenditures for the following: i) $14.5 million variance (68% over budget) between budgeted and actual expenditures for Residential and Commercial Additions and ii) $6 million variance (67% over budget) for Distribution Integrity expenditures. Such explanation should include (to the extent applicable) the identified material and quantity cost variances between budget and actual.

RESPONSE: See attachment.

Name and Title of Preparer: John Robson, Director - Gas FP&A

Name and Title of Responsible Person: Joel Rutledge, Director - Finance Gas Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-106. Provide a comprehensive explanation of the extent to which internal approval is required in those situations in which it becomes apparent that the total annual capital expenditures will exceed budgeted expenditures. Provide a copy of any such support submitted to management supported the additional expenditure of funds which may apply to 2017 – 2019 capital expenditures.

RESPONSE: Monthly, Piedmont reviews individual project cost projections as set forth in the original capital budget and makes adjustments as necessary to arrive at current projected costs by project. In-service dates are also adjusted based on projected construction delays or acceleration, specific to each project. All of these adjustments are constantly changing the expected spend during the fiscal year. If the projected spend exceeds the current authorized amount, an electronically generated approval is required based on appropriate authority levels. Final updates to capital project projections are determined at intervals during the year, usually the 4th, 8th and 11th months of the year. This is done at a Duke Energy Corporation level at a routine monthly finance meeting. Approved changes to capital project spend projections are then communicated to management of the Natural Gas Business segment.

Duke Energy's capital spend policy requires all capital projects estimated to exceed $50 million be approved by Duke Energy executive management. An internal document referred to as a whitepaper is created with all of the project components including cost and project description. In Nashville, Piedmont has one such project, Line 431 Ph II. The whitepaper for this project is attached.

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Name and Title of Preparer: John Robson, Director - FP&A Gas

Name and Title of Responsible Person: Joel Rutledge, Director - Gas Finance Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Report to the Transaction & Risk Committee

Line 431 Phase II Project

1 – Executive Summary

1.1 – Transaction Summary

Piedmont Natural Gas (Piedmont) proposes to install a new 20" transmission pipeline (Line 431 Phase II) and 12" transmission lateral pipeline (Line 469) to functionally replace Piedmont Line 310 to support the Transmission Integrity Management Program (TIMP) as required by Federal Regulations. Line 310 will be reclassified from transmission to distribution operation after Line 431 Phase II is placed in-service. The project corridor begins at the intersection of new Line 431 Phase I tie-in to Line 310 in the Bordeaux neighborhood of Nashville, TN and will continue primarily in a dedicated easement to the Holts Holder pipeline interconnect station located in Whites Creek, TN (see map on page 3). The project is eligible for inclusion in the Integrity Management Rider (IMR) and is scheduled to be placed into service on or before October 15, 2020.

1.2 – Recommendation to Management

Piedmont requests regular funding of $62.7 million for the project. Project spend to through October 2019 is $3.5 million.

1.3 – Project Description

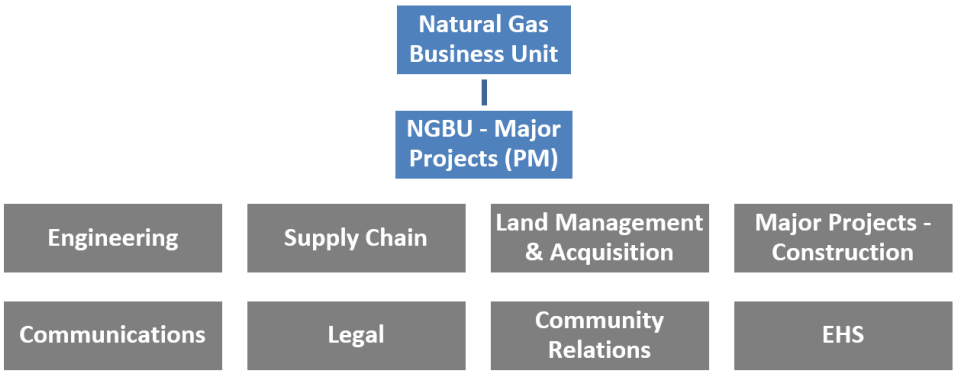
Business Unit	Natural Gas Business Unit					
Executive Sponsor	Victor Gaglio					
Project Location	Nashville, Tennessee					
Investment Date	2018-2021					
In-Service Date	October 15, 2020					
Project Capital Costs	$ 62.7 Million	Variance from Current Financial Plan* [favorable (unfavorable)]:	$ (24.6) Million			
Direct Project O&M Costs	$ - Million	Variance from Current Financial Plan* [favorable (unfavorable)]:	$ - Million			
Are any O&M savings from the project reflected in the Current Financial Plan*?	No	Are any incremental, ongoing O&M costs included in the Current Financial Plan*?	No			
Project Expected Return	Unlevered Return:	IRR	WACC	Levered Return:	IRR	WACC
		7.10%	7.05%		10.08%	10.20%
Existence of Enterprise Risks	☐ Yes ☒ No					
Project Cost Estimate Class	Class III					
Project Profile Matrix Ranking	Green II					

Document Version Control

Whitepaper Version: FINAL	TRC Meeting Date: Tuesday, November 26, 2019

* References to the "Current Financial Plan" represent the current 8x4 financial plan.

2 – Transaction Description



2.1 – Strategic Rationale

Piedmont is committed to providing safe, reliable gas service and continues to expand our In-Line Inspection (ILI) program either through pipeline retrofits, where able, or through replacement projects. This project has been selected to be constructed to fulfill regulatory obligations to be able to inspect the integrity of our pipelines using latest techniques and technologies as well as to regain the prior level of deliverable capacity from Piedmont's Kinder-Portland Station (K-P) to serve Piedmont's Tennessee service area. Line 431 will functionally replace Line 310 as the main transmission line from K-P to the city of Nashville and Piedmont's Nashville LNG Plant (LNG). Specifically, Line 431 Phase 2 will complete the final phase of a continuous 20" transmission pipeline from K-P to LNG consisting of Line 301 Phase 1 (2004), Line 301 Phase 2 (2005) and Line 431 Phase 1 (2019).

Line 310 must remain in-service until Line 431 Phase II is operational. The current maximum allowable operating pressure (MAOP) of Line 310 is 735 PSIG. This line will have in-line inspection (ILI) in the first half of 2020. Any anomalies found will be addressed. After reclassifying to distribution operation, the new MAOP of Line 310 will be 75 PSIG, and this reclassified pipeline will become one of the major feeds to the northern Davidson County distribution system. Additionally, three regulator stations currently connected to Line 310 will be removed from service lowering operation and maintenance costs. After this reclassification, Line 310 will be removed from the Transmission Integrity Management Program. As a 12" distribution pipeline, it will meet all requirements of the Distribution Integrity Management Program. Line 431 will have a 1000 PSIG MAOP.

Historically, Line 310 and Line 309 were the main transmission lines from Holts Holder Valve Station into Nashville. Constructed in 1946, the 8" Line 309 was the original transmission line into Nashville but was retired in 2014 as part of TIMP review. Line 309 lacked adequate records and had integrity issues discovered by in line inspection. Therefore, the new 20" Line 431 will regain deliverable capacity lost by the retirement of Line 309. After completion of Line 431, Piedmont will be able to ILI the entire 20" pipeline from KP Station to the Nashville LNG plant.

2.2 – Background

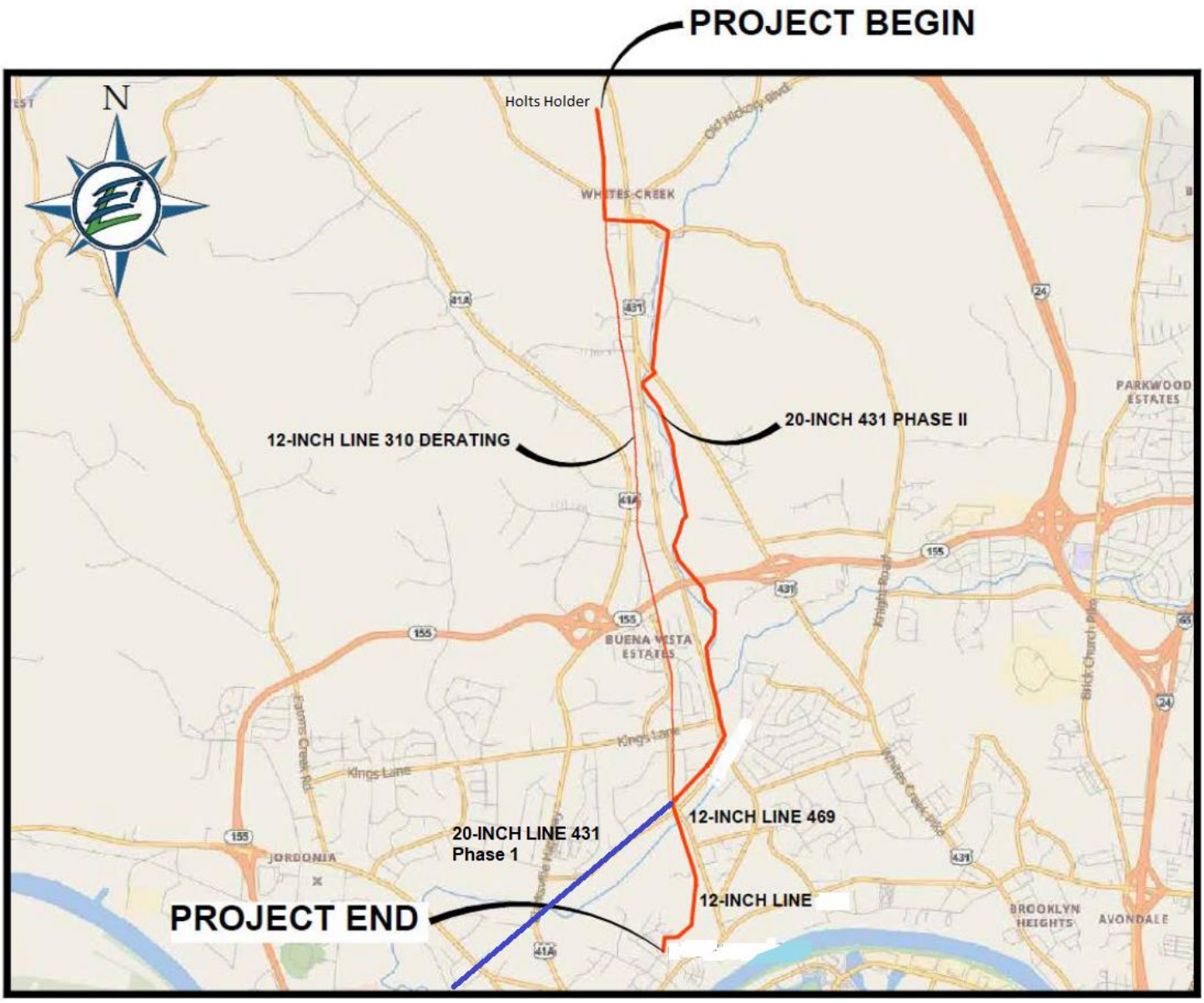
Constructed in 1956, Line 310 does not have adequate test records or other documentation to meet current regulatory requirements. Piedmont's Transmission Integrity Management department therefore advocates replacement of Nashville Line 310. System Planning evaluated the operation of the connecting pipelines (both 20") and lost capacity from the retirement of Line 309 to appropriately size the replacement pipeline. The existing easement for Line 310 acquired in 1955 and 1956 is 40' wide and is now adjacent to heavy residential development on both sides from Tucker Rd. in Bordeaux to Knight Dr. in Whites Creek - approximately 3.5 miles. This is not sufficient area to install a 20" pipeline safely, efficiently, or economically. The first 3,600' of Line 431 from Holts Holder heading south will be in the original easement which has been expanded to the company standard 50', and we have also acquired sufficient temporary construction easement to safely and efficiently build the pipeline. The new dedicated easement for Line 431 is primarily located in undevelopable land in floodway which reduces the probability of 3rd party damage.

2.3 – Scope

Line 431 scope includes the installation of a new pipeline and additional easements for permanent right of way and temporary construction workspace. The new, de-rated, and retired assets consist of the following:

Installation of approximately 5 miles of 20" x 0.375" steel pipeline (API 5L PSL-2 X65) and approximately 1 mile of 12" x 0.375" steel pipeline (API 5L PSL-2 X52)

- Eight (8) horizontal direction drills (~2.5 miles)
    - Seven (7) 20" diameter HDD's
        - HDD#1 - Old Hickory Bv, Earthman Creek trib. (900')
        - HDD#2 - Whites Creek Pk, Knight Dr, Earthman Fork Creek (1360')
        - HDD#3 - Fontanel Entertainment Complex, Metro greenway, Whites Creek (3435')
        - HDD#4 - Bates Nursery (1200')
        - HDD#5 - Green Lane, hilly topography, possible landslide issue (2064')
        - HDD#6 - Briley Pkwy (975')
        - HDD#7 - Whites Creek – 20", Buena Vista Ln (1060')
    - One (1) 12" diameter HDD
        - HDD#8 - Whites Creek – 12", Hartman Park (1820')
- One pressure regulator addition for the 75 PSIG distribution system to Bordeaux Station
- De-rate Line 310 from transmission to 75 PSIG distribution operation (5.25 miles)
- Retire three (3) regulator stations and one (1) farm tap from line 310



Project Overview Map

2.4 – Schedule & Milestones

Line 431 Phase 2 project was initiated in February 2018 for project design. The construction is scheduled to start in December 2019 with a forecasted in-service date by October 2020.

DATE	LINE 431 MILESTONES
FEB 2018	Project Design Initiation
MAR 2019	Refine Primary and Alternate Routes 60% Design Complete
SEP 2019	Complete Design RFP for Construction
OCT 2019	Receive all Permits
NOV 2019	Complete Easement Acquisition
DEC 2019	All Materials Received TRC Approval Construction Contractor Mobilization
SEP 2020	Mechanically Complete
OCT 2020	Pipeline In-Service

2.5 – Contractor/Vendor/Technology Selection

The engineering design firm and construction contractor selections are based upon a competitive bid process though PowerAdvocate. The bid lists for both engineering and construction were restricted to companies with a solid history of satisfactorily designing and constructing projects of this magnitude. The proposals were evaluated based on compliance with key project requirements, past performance, the strength of the proposed project team, bench strength, cost competitiveness and any unique strategies, capabilities or solutions identified in the proposals.

The project does not include utilization of any unique or first of a kind technology.

2.6 – Contractual Structure, Compliance & Legal Discussion

The competitively bid contract for engineering design services was awarded to Energy, Land and Infrastructure. The construction services bids are currently being evaluated and were bid to Troy Construction, Snelson Companies, Inc., Infrasource, Henkels & McCoy, and Price Gregory International.

Procurement of owner furnished material including pipe, fittings, equipment and valves were purchased through the NGBU Supply Chain department.

Easement acquisition services were contracted to a 3rd party firm, Croft and Associates, led by a Piedmont Land Agent, managing a team of land agents.

Cleveland Integrity Services, Inc, one of NGBU's preferred alliance inspection firms, has been selected for field inspection services. HDR, an Enterprise Engineer of Choice partner, will supply a dedicated horizontal direction drill consultant.

ACUREN, one of NGBU's preferred alliance non-destructive examination (NDE) firms, will be used to provide NDE services.

Pre-Construction permits have been acquired.

2.7 – Regulatory Recovery Requirements & Considerations

This project will create a utility asset providing benefit to Piedmont's general body of customers in Tennessee, and will therefore become part of Piedmont's regulated utility rate base. Capitalized costs associated with replacement of transmission pipelines under the NGBU TIMP are eligible for recovery via rates as part of Piedmont's Tennessee Public Utilities Commission (TPUC)-approved Tennessee Integrity Management Rider (IMR). The TN IMR is a favorable alternative regulatory mechanism that enables the Company to earn a return of and on its safety and integrity-related capital investment, which includes compensation for incremental depreciation expense. Absent the TN IMR, cost recovery on such capital investment would begin only after its inclusion in rate base as part of a general rate case proceeding.

Under the TN IMR, 100% of TIMP capital investment is eligible for rate relief. Such TN IMR capital expenditures occurring between November 1 and October 31 are eligible for recovery via rates starting the following January. Given the anticipated October 2020 in service date for this project, its costs recorded to CWIP through October 31, 2020 would be eligible for rate relief via the TN IMR beginning in January 2021. Rate relief for the remainder of the project cost would begin via the TN IMR rates effective January 2022.

2.8 – Environmental Issues & Discussion

Due to the size and scope of the project and the natural conditions in the project area, impacts to streams and wetlands are unavoidable, thus we have obtained a Section 404 Nationwide Permit 12 (NWP12) for Utility Line Activities from the U.S. Army Corps of Engineers (USACE) and an Aquatic Resource Alteration Permit (ARAP)/401 Water Quality Certification from TN Department of Environment and Conservation (TDEC). No impacts to protected species or to cultural resources are anticipated. All Section 7 and 106 clearances required by the USACE related to Waters of the U.S. (WOTUS) impacts have been obtained for the Project. Additional cultural resource investigations have been completed for the entire project alignment, access roads, laydown yards, and other temporary workspaces and avoidance and mitigation measures are to be employed to protect identified cultural resources.

The project has an Erosion and Sediment Control permit issued by TDEC due to land disturbances greater than 1 acre. A project specific Stormwater Pollution Prevention Plan (SWP3) has been developed and approved and erosion/sedimentation controls will be installed, maintained, and monitored as per the SWP3 and the permit. The permit will remain open and monitoring activities will continue until the permit can be closed out when the project is at final stabilization (70% cover) as defined by TDEC. The project SWP3 was developed to meet both TDEC and Metro Water Services permit requirements.

A Hydrostatic Pressure Test Water Discharge permit has also been acquired.

The project plans include HDDs which create a potential for Inadvertent Returns (IR) of drilling mud. An IR Contingency Plan has been developed and will be followed by the construction contractor. Drilling mud pressures and volumes will be closely monitored during HDD activities and any losses investigated as a potential IR. Regular pedestrian surveys will also occur along likely IR locations. Any identified IRs will be contained as appropriate and if required, drilling will cease until the IR can be contained and managed. The protocol for contacting Duke Energy and state/federal environmental regulators is detailed in the IR Contingency Plan.

Above-ground facilities have been sited to avoid FEMA 100-year floodplains. Workspace areas located within 100-year floodplains will be restored to pre-existing contours and re-vegetated with an appropriate seed mix. No alteration to flow pattern, profile, dimension, or volume is expected to result from project construction or operation, such alterations if they did occur could trigger the need for floodplain permitting.

2.9 – Accounting Issues

There are no known accounting issues associated with the project.

2.10 – Tax Issues

There are no known tax issues associated with the project.

2.11 – Insurance Issues

There are no known insurance issues associated with the project.

3 – Analysis

3.1 – Alternative Analysis

Considering the requirements outlined under Strategic Rational in Section 2.1, once TIMP determined replacement was necessary System Planning recommended the replacement pipeline size to be 20” to accommodate the NGBU design basis requirements for pipeline in-line inspection and to regain lost capacity from the retirement of Line 309.

The alternative of completely abandoning the affected line without replacement is not a viable option since Line 310 is the gas supply backbone for the Nashville, TN service area. Nashville is served primarily from K-P station in northwest Davidson County and by Columbia Gulf Stations 1 and 4 in southeast Davidson County via Line 383.

3.2 – Project Costs & Contingency

Primary variance from budget is related to higher than expected construction bids because of the design of eight horizontal directional rock drills, seven of which were not included in previous budget. Additionally, easement acquisition has been more expensive than originally estimated because of emerging project development plans on previously undesired properties.

The construction risks associated with Line 431 are encountering waters of the state, terrain features and subsurface limestone rock. However, this project will be utilizing proven construction installation technologies that have been used to install pipelines for decades so the construction risk is limited. Pre-selected construction companies will have the capability to provide multiple pipeline installation crews to limit schedule delays related to these risks.

The overall project costs broken out in major categories are as follows:

Description	Line 431 Pipeline and Facilities
Engineering	$ 1,421,058
Land	4,543,062
Materials/Equipment	4,732,753
Construction - Pipeline	34,597,663
Construction - Facility	50,000
Field Inspection	4,445,000
Internal Labor	792,288
Other Direct Costs	403,963
Contingency	6,981,500
Sub-Total	***58,250,869***
Overheads	3,253,149
Sub-Total	***61,054,018***
AFUDC	1,233,539
Grand Total	**$ 62,737,557**

3.3 – Key Assumptions

The project's key assumptions are as follows:

- Land – Easements/Right-of-Entry are currently in acquisition with approximately 40 of the 74 total parcels acquired or right-of-entry granted. Of the 34 remaining, 31 are Metropolitan Government of Nashville and Davidson County properties which are being negotiated collectively.
- Materials – All major materials have been procured and are being received at the project laydown yards to support on-time construction start.

3.4 – Financial Analysis

Financial Plan

Is the capital expenditure for the proposed project included in the current financial plan? (if yes, see below)	Yes
Do the project costs include any O&M amounts? (if yes, see below)	No
Will any O&M savings result from the project? (if yes, see below)	No
Will the project result in any incremental, ongoing O&M costs? (if yes, see below)	No

Financial Summary

Project Costs ($ in Millions)	2018	2019	2020	2021	2022	2023	2024
Project CapEx reflected in the financial plan		$6.9	$22.7	$3.6	$ -	$ -	$ -
Project CapEx not reflected in the capital plan		2.7	29.6	(2.9)	-	-	-
Total Project Capex	**$0.2**	**$9.6**	**$52.3**	**$0.7**	**$ -**	**$ -**	**$ -**

Income Statement Information:	2018	2019	2020	2021	2022	2023	
AFUDC	$ -	$ 0.2	$ 1.5	$ -	$ -	$ -	$ -
Direct Project O&M Costs		-	-	-	-	-	-
Net Income		$ 0.1	$ (0.1)	$ 2.8	$ 3.2	$ 3.0	$ 2.9
Pro Forma Return on Equity		**1.6%**	**(0.2%)**	**9.2%**	**10.8%**	**10.8%**	**10.8%**

Information on O&M savings expected to result from the project (if applicable):

N/A

Information on incremental, ongoing O&M costs (if applicable):

N/A

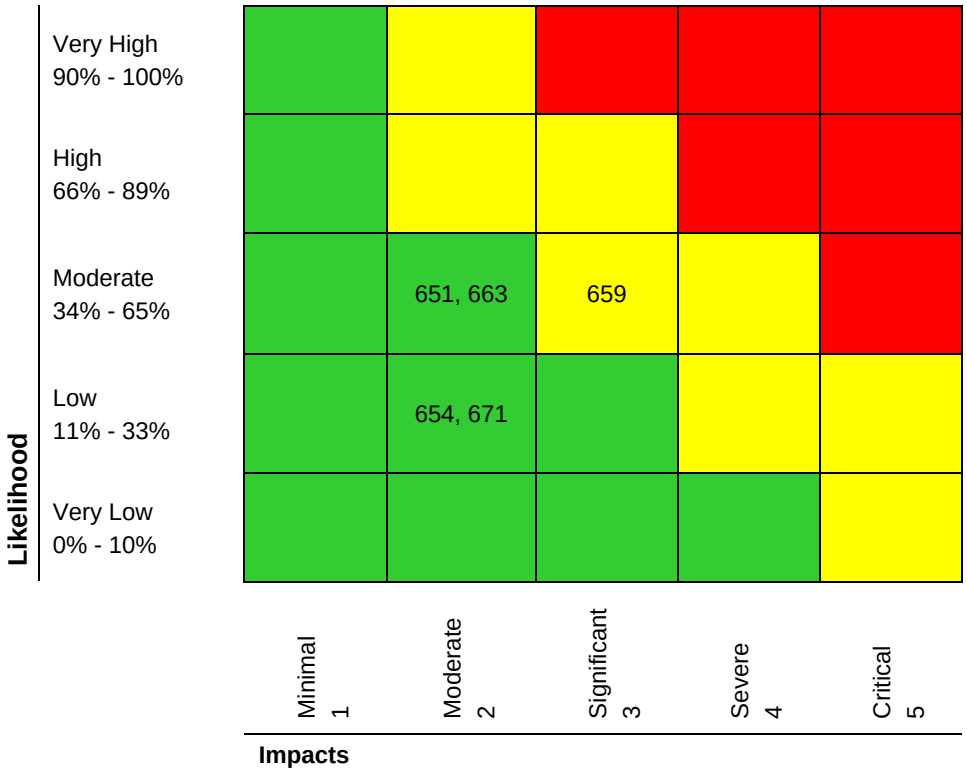
Regulatory Lag

($ in Millions)	2019	2020	2021	2022	2023	2024
Annual Retail Revenues	$ -	$ -	$ 7.0	$ 7.4	$ 7.2	$ 7.0
Pro Forma Revenue Requirement	$ -	1.5	7.4	7.2	7.0	6.8
Regulatory Revenue Lag	**$ -**	**$ (1.5)**	**$ (0.4)**	**$ 0.2**	**$ 0.2**	**$ 0.2**

4 – Risks & Mitigations and Stakeholder Discussion

4.1 – Risks & Mitigations

Risk Matrix



Risk Description		Impact	Mitigation
659	Environmental Construction Impacts	F	Identify any areas of concern and provide detailed erosion and sediment control plan to contractor prior to construction. Require daily/weekly updates from contractor during entire construction.
663	Easements Not Obtained	F	Ensure land, materials and permits are on-schedule. Prioritize land acquisition to maximize time available for condemnation.
654	Community opposition	F, R	Coordinate with corporate communications. Have land agents investigate potential for contentious landowners. Engage Government and Community Relations when necessary.
651	Construction Interferences	F	Explicitly identify concerns in construction bid documents. Require construction contractor to provide excavation procedure that is accepted by Piedmont. Require soft digs on site.
671	Late Materials	F	Order all materials to provide delivery at least 30 days prior to start of construction. Perform bi-weekly review of delivery status prior to construction. Review material weekly during construction.
*Risk Matrix and Descriptions showing top five risks only. Complete Risk Register has been reviewed and approved by PMCoE.			
Impacts Explanations: F = Financial; R = Reputational; O = Operational, Legal and Compliance			

Enterprise Risks

None

4.2 – Stakeholder Discussion

Stakeholder	Discussion of Interest & Impact	Assessment
Customers	Customers will receive a more reliable supply of gas with increase in capacity	F
Community	We have informed Corporate Communications, Government Relations and Community Relations about this project. Our land agents and legal representatives are in contact with affected property owners.	F
Employees	This pipeline is needed to safely serve our customers.	F
Shareholders	Reduce future costs associated with pipeline failures.	F
Regulators	This project should be supported by the regulators as it improves pipeline integrity management conditions	F
Note: Favorable (F); Unfavorable (U); Neutral (N)		

5 – Assessment of Adhere to Corporate Governance

Fully complied with all corporate governance.

TRC Review Schedule

Milestone	Due Date	Date Completed	Compliance (Y/N)
TRC Whitepaper	October 28, 2019	October 28, 2019	Y
TRC Scrub Team Meeting	October 30, 2019	October 30, 2019	Y
TRC Scrub Team Final Sign-Off	November 13, 2019	November 13, 2019	Y
TRC Final Materials	November 18, 2019	November 18, 2019	Y
TRC Meeting	November 26, 2019	November 26, 2019	Y
Board of Directors Materials	N/A		
Board of Directors Meeting	N/A		

Project Management Center of Excellence (PMCoE) Review

Milestone	Due Date	Date Completed	Compliance (Y/N)
Risk Register Completed			
Independent Review Board Estimate (including contingency review)		10/22/2019	N/A – this is a GII ranked project. An internal IERB was performed but did not include PMCoE

Appendix 1 – Summary of Material Contracts

Engineering Agreements

	Contract Terms & Conditions	Open Items, Issues & Legal Comments, Minimum Acceptable Position if still under negotiation
Duke Energy Legal Entity	Piedmont Natural Gas, Inc.	None
Service Agreement Counterparty	Energy, Land and Infrastructure	None
Services to be Performed	Engineering and Survey	None
Contract Term (years)	Duration of the project	None
Contract Price & Fees	Time and Material - $1,009,060	None
Payment Terms	30 days ACH	None
Credit Security Requirements	N/A	None
Liquidated Damages	N/A	None
Termination Provisions	Piedmont can terminate for convenience and for cause	None
Suspension Provisions	At any time by Piedmont	None
Force Majeure	Governed by and subject to the terms of the contractor's Master Services Agreement	None
Warranty	N/A	None
Indemnification	N/A	None
Limitation of Liability	N/A	None
Dispute Resolution	N/A	None

Master Transmission Pipeline Construction Contract

	Contract Terms & Conditions	Open Items, Issues & Legal Comments, Minimum Acceptable Position if still under negotiation
Piedmont Natural Gas Company	TBD	Bids currently in evaluation
EPC Counterparty	N/A	N/A
Contract Price	Fixed Price	Bids currently in evaluation
Payment Terms	45 days ACH	None
Credit Security Requirements	TBD	Dependent on Contractor, Letter of Credit or Parent Guarantee
Liquidated Damages	Delay liquidated damages as agreed up and set forth in the PO.	Will be negotiated to awarded bidder
Performance Guarantees	Contractor warrants the work meets Piedmont and industry standards. Schedule will include milestone events such as Substantial Completion and Final Acceptance.	None
Termination Provisions	Piedmont has right to terminate for convenience or cause.	None
Suspension Provisions	At any time by Piedmont.	None
Force Majeure	Governed by and subject to the terms of the contractor's Master Services Agreement	None

	Contract Terms & Conditions	Open Items, Issues & Legal Comments, Minimum Acceptable Position if still under negotiation
Indemnification	Governed by and subject to the terms of the contractor's Master Services Agreement	None
Limitation of Liability	N/A	None
Dispute Resolution	7 days of executive discussions, if not resolved then unless the Parties otherwise expressly agree in writing, disputes will be resolved by arbitration (AAA).	None

Appendix 2 – Financial Analysis

Income Statement View ($ in thousands)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Retail Rates Rider Recovery	-	-	-	7,029	7,448	7,233	7,022	6,821	6,630	6,444	6,259	6,073	5,888	5,703	5,518
Retail Rate Case Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wholesale Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC	2	216	1,547	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	(92)	(444)	(448)	(452)	(456)	(460)	(464)	(469)	(473)	(478)	(483)	(488)	(493)
Operating Income	2	216	1,456	6,585	7,000	6,781	6,566	6,361	6,165	5,975	5,785	5,595	5,406	5,216	5,026
Depreciation Expense	-	-	(776)	(1,560)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)
Interest Expense	(3)	(111)	(779)	(1,320)	(1,273)	(1,220)	(1,170)	(1,122)	(1,076)	(1,031)	(985)	(939)	(894)	(848)	(803)
Income Taxes	0	(25)	23	(875)	(983)	(943)	(904)	(867)	(832)	(798)	(764)	(730)	(695)	(661)	(627)
Net Income	(0)	80	(75)	2,829	3,176	3,049	2,923	2,803	2,689	2,578	2,468	2,358	2,248	2,137	2,027
Net Income	(0)	80	(75)	2,829	3,176	3,049	2,923	2,803	2,689	2,578	2,468	2,358	2,248	2,137	2,027
Owners' Equity	121	5,152	31,792	30,810	29,529	28,312	27,154	26,049	24,970	23,891	22,811	21,731	20,651	19,572	18,492
ROE	- 0.10%	1.55%	- 0.24%	9.18%	10.76%	10.77%	10.76%	10.76%	10.77%	10.79%	10.82%	10.85%	10.88%	10.92%	10.96%

Regulatory Revenue Lag ($ in thousands)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Revenues	-	-	-	7,029	7,448	7,233	7,022	6,821	6,630	6,444	6,259	6,073	5,888	5,703	5,518
Pro Forma Annual Revenue Requirement	-	-	(1,479)	(7,448)	(7,233)	(7,022)	(6,821)	(6,630)	(6,444)	(6,259)	(6,073)	(5,888)	(5,703)	(5,518)	(5,334)
Regulatory Revenue Lag	-	-	(1,479)	(419)	215	211	201	191	186	185	185	185	185	185	185

Economic Return ($ in thousands)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Direct Method															
EBITDA	2	216	1,456	6,585	7,000	6,781	6,566	6,361	6,165	5,975	5,785	5,595	5,406	5,216	5,026
Less: Non-Cash AFUDC	(2)	(216)	(1,547)	-	-	-	-	-	-	-	-	-	-	-	-
Adj EBITDA	-	-	(92)	6,585	7,000	6,781	6,566	6,361	6,165	5,975	5,785	5,595	5,406	5,216	5,026
Taxes on EBITDA	-	-	22	(1,556)	(1,654)	(1,602)	(1,551)	(1,503)	(1,457)	(1,412)	(1,367)	(1,322)	(1,277)	(1,232)	(1,188)
Depreciation Tax Shield	-	-	183	369	371	371	371	371	371	371	371	371	371	371	371
Change in Deferred Taxes	-	-	946	993	863	740	629	528	480	479	481	479	481	479	481
Terminal Value (after-tax)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Expenditures	(227)	(9,330)	(50,726)	(689)	-	-	-	-	-	-	-	-	-	-	-
Unlevered After-Tax Cash Flows	(227)	(9,330)	(49,666)	5,701	6,579	6,289	6,014	5,757	5,559	5,413	5,270	5,123	4,980	4,833	4,690
Interest Expense	(3)	(111)	(779)	(1,320)	(1,273)	(1,220)	(1,170)	(1,122)	(1,076)	(1,031)	(985)	(939)	(894)	(848)	(803)
Interest Expense Tax Shield	1	26	184	312	301	288	276	265	254	244	233	222	211	200	190
Debt Financing	109	4,515	23,911	(882)	(1,150)	(1,092)	(1,039)	(992)	(969)	(969)	(969)	(969)	(969)	(969)	(969)
Debt Re-payment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levered After-Tax Cash Flows	(121)	(4,900)	(26,350)	3,812	4,457	4,266	4,081	3,908	3,768	3,658	3,548	3,437	3,328	3,217	3,107

Sensitivities

As the TN IMR is designed to capture all capital incurred, whether the project is in service or still under construction there is no meaningful sensitivity around the timing of recover.

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1-107. Provide a copy of any revisions to the PNG-TN 2020/2021 capital budget which have been submitted to management since June 1, 2020.

RESPONSE: N/A. There have been no such revisions since June 1, 2020.

Name and Title of Preparer: John Robson, Director - Gas Distribution Finance

Name and Title of Responsible Person: Joel Rutledge, Director - Finance Gas Segment

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

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1-108. With respect to any real-estate assets whose costs (including depreciation and/or return) are either direct charged or allocated to PNG-Tennessee identify whether any are a) currently listed for sale or b) not currently in use.

RESPONSE: Neither the PNG Tennessee plant in service balance in this rate case nor the CWIP balance in this rate case (both of which consist of Piedmont Tennessee direct property and an allocated portion of Piedmont 3-state joint property) includes any real estate assets currently listed for sale or any plant held for future use.

Name and Title of Preparer: Laura Hager, Lead Rates & Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

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1-109. Provide the underlying support for the per-book recording of Income Tax Expense for PNG-Tennessee for calendar year 2019.

RESPONSE: See attachment.

Name and Title of Preparers: Chris Nelson, Tax Services Manager; Brian Neiheisel, Senior Tax Services Manager

Name and Title of Responsible Person: John Panizza, Director - Tax Operations

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-110. Provide the number of customers by customer class that were 60 days past due in their Piedmont bill as of June 30, 2019 and June 30, 2020.

RESPONSE: As of June 30, 2019, there were 6,624 customers 60 days or more past due. Of these, 6,238 were residential and 386 were non-residential. As of June 30, 2020, there were 8,835 customers 60 days or more past due. Of these, 7,960 were residential and 875 were non-residential.

Name and Title of Preparer: Melissa Churchill, Manager - Revenue Services

Name and Title of Responsible Person: Melissa Churchill, Manager - Revenue Services

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-111. Of the residential customers with past due balances of 60 days or more as of June 30, 2020 identify the number of customers who also subscribe (or formerly subscribed prior to termination) to the voluntary Gas Line Coverage from HomeServe.

RESPONSE: As of July 7, 2020 (the oldest date available at this time), there were 473 Tennessee customers with gas line coverage that were past due 60 days. This amount is out of a total of 21,811 gas line coverage customers in Tennessee.

Name and Title of Preparer: Melissa Churchill, Manager - Revenue Services

Name and Title of Responsible Person: Melissa Churchill, Manager - Revenue Services

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-112. Provide a comprehensive explanation of how Piedmont applies partial payments to outstanding balances due under the following hypothetical example: Assume a customer owes $200, which includes a past due balance for natural gas service of as well as past due balances for Gas Line Coverage charges (HomeServe). If a customer makes a payment of $100, will the payment be applied a) first to any outstanding balance due for natural gas service, b) pro-rata for all outstanding charges including Gas Line Coverage charges, or c) applied first to Gas Line Coverage charges, with residual amounts applied to the outstanding natural gas service balance?

RESPONSE: Payment is applied to the oldest balances first, with highest priority to regulated natural gas services. There is no proration.

For example, assume the customer owes $200 and is 66 days past due. Of this amount, assume that the total amount that is 60-89 days past due is $80, of which $10 is for gas line coverage and $70 is for regulated natural gas services. Also assume that the total amount that is 30-59 days past due is $60, of which $10 is for gas line coverage and $50 is for regulated natural gas services. Lastly, assume that the remaining $60 owed is for the current bill, of which $10 is for gas line coverage and $50 is for regulated natural gas services ($200 total amount owed, from oldest to newest balance, is $80 + $60 + $60).

A $100 payment on the customer's account would be first applied to $70 for natural gas service, then the $10 for gas line coverage, because these amounts are the associated with the oldest past due balance. The remaining $20 of the payment ($100 less the $80 applied

to the oldest past due balance) would be applied to the second oldest balance, which in this example is the balance that is between 30-59 days past due. Recall that in this category for this example, the customer owes $10 for gas line coverage and $50 for natural gas services. Since there only remains a $20 payment to apply, all of it would be applied to the regulated natural gas services portion of the 30-59 day past due balance.

Name and Title of Preparer: Melissa Churchill, Manager - Revenue Services

Name and Title of Responsible Person: Melissa Churchill, Manager - Revenue Services

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
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1-113. Refer to the tabs PNG Balance Sheet – 2019 and PNG Bal Sheet March 2020 within MFR 11, specifically to the balances in Account 106 and Account 108 within each respective Balance Sheet. Please respond to the following questions:

a. Has the Company calculated Depreciation Expense for the period January 1, 2017 – current on i) the entire monthly balance of Account 106 or ii) a portion of the monthly balance of Account 106?

b. Provide a comprehensive explanation how Depreciation Expense has been determined on Account 106 balances for the period January 1, 2017 through current. This discussion should incorporate an explanation of how the Company has assigned the unclassified balances to individual accounts for purposes of computing Depreciation Expense.

c. Provide a comprehensive explanation of the impact on Depreciation Expense and Accumulated Depreciation long-standing amounts of plant recorded to Account 106 are eventually classified within account 101 Plant in Service.

d. Provide the support for the accounting entries made to Depreciation Expense and Accumulated Depreciation associated with plant balances which were reclassified from Account 106 to Account 101 during the months of January 2020 through the end of March 2020.

RESPONSE:

a. Yes. Depreciation expense has been calculated on the entire balance of accounts 0101000 and 0106000.

b. Depreciation expense is calculated monthly by multiplying the depreciation rate for each utility account by the prior month balance in each utility account within general ledger accounts 0101000 and 0106000, divided by 12. Prior to project unitization, which is the process that transfers project costs from account 0106000 to 0101000, project charges within 0106000 are generally allocated to specific plant accounts in alignment with the total project cost estimate by plant account which is established at such time the project is approved.

c. The Company has not performed an analysis to determine such impact.

d. Piedmont uses group depreciation, which means depreciation is not recorded at an asset level. There is no way to isolate the entries recorded to depreciation expense and accumulated depreciation associated with just the plant balances reclassified from account 0106000 to account 0101000.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analyst

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-114. Please document all assumptions made concerning the Company's balances of Account 106 incorporated into the Depreciation study of Mr. Watson.

RESPONSE: Piedmont provided Alliance Consulting with Account 106 balances including a utility account based on the construction estimate. The construction estimate is used to initially classify completed construction not classified, prior to unitization. Alliance Consulting used this detail to appropriately classify the asset balances to plant in service for purposes of the depreciation study.

Name and Title of Preparer: Denise Lepisto, Lead Accounting Analysis

Name and Title of Responsible Person: David Raiford, Accounting Manager

Response provided by Piedmont Natural Gas Company, Inc. on September 4, 2020.

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1-115. Confidential - Regarding severance costs included within the proposed revenue requirement, provide the rationale for recovery of such costs from Tennessee ratepayers.

RESPONSE: These costs are normal and reasonable expenses incurred by a business.

Name and Title of Preparer: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-116. Confidential - Regarding retention costs included within the proposed revenue requirement, identify the total costs included in the revenue requirement proposal, the account(s) charged and the rationale for recovery of such costs.

RESPONSE: See attached for costs included within the proposed revenue requirement.

On a very limited basis, the Company enters into retention agreements with employees if it is determined that the employee's knowledge and skills are critical to retain to maintain safe and reliable business operations on behalf of our customers.

Name and Title of Preparer: Patti Doster, Lead Accounting Analyst

Name and Title of Responsible Person: David Dye, Manager - Accounting II

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

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1-117. Refer to the Company's Service Schedule No. 316, the Performance Incentive Plan. Specifically, refer to the 'Fourth revised page 5 of 7' and section "Gas Supply Incentive Compensation Program." Provide answers to the following:

a. What account are these charges recorded to?

b. What was the amount of compensation provided under this program for 2017, 2018, and 2019.

c. A detailed discussion describing how the amount of gas supply incentive compensation is calculated for an employee earning this type of compensation.

RESPONSE: The Gas Supply Incentive Compensation Program ("Program") was terminated in 2017. Neither the Test Period nor the Attrition Period for this rate case proceeding include costs associated with the Program.

a. Payments under the Program were charged to account 0920000.

b. 2016/2017 plan year awards were paid in March 2018 for the period November 1, 2016 – December 31, 2017 in the amount of $82,252.05. The Program ended with the plan year that ended December 31, 2017.

c. The amount of gas supply incentive compensation for an employee in the Program was calculated by first setting secondary marketing margin targets of Threshold, Target, Stretch and Super Stretch and percentages of annual salaries assigned for each employee participating in the Program for each level of target for the plan year. After the plan year was completed, a request of the actual secondary marketing margin booked to the ledger from Gas Accounting were requested and payouts were calculated based on each employee's salary. For example, assume

secondary marketing margin targets of $10,000,000 for Threshold, $12,000,000 for Target, $14,000,000 for Stretch, and $16,000,000 for Super Stretch and targets of 5%, 10%, 15% and 20% respectively for an employee whose salary is $100,000. If the actual secondary margin was $12,000,000, then the calculation would be 10% of $100,000 equating to a payout of $10,000.

Name and Title of Preparer: Sarah Stabley, Managing Director - Gas Supply and Optimization

Name and Title of Responsible Person: Sarah Stabley, Managing Director - Gas Supply and Optimization

Response provided by Piedmont Natural Gas Company, Inc. on September 3, 2020.

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1-118. Refer to "5F_OtherBen Adj.xlsx" as provided with the Company's filing. Specifically, provide the following regarding the Company's "Retirement Savings Plan":

a) All materials provided to employees outlining the program.

b) A descriptive explanation for the use of the term 'incentive' within the journal descriptions provided in Column P of tab "RSP details."

RESPONSE:

a. See the 6 attachments.

b. The term 'incentive' within the journal descriptions in Column P of tab 'RSP details' in the file "5F_OtherBen Adj.xlsx" refers to the Duke Energy Short-Term Incentive Plan. These journal entries are 401(k) match accruals based on the short-term incentive accruals. The short-term incentive plan (STI) is the annual cash incentive plan that is available to all employees at Duke Energy.

Name and Title of Preparer: Jennifer Edwards, Lead HR Consultant

Name and Title of Responsible Person: Jake Stewart, Director Compensation

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

Important Changes to Your Pension Plan

For participants in the Retirement Plan of Piedmont Natural Gas Company, Inc.

[Insert date], 2017

Duke Energy is making important changes to the Retirement Plan of Piedmont Natural Gas Company, Inc. (the "Piedmont Retirement Plan") effective after Dec. 31, 2017. As you review this notice, please note that none of these changes affect the accrued pension benefit you have earned through Dec. 31, 2017. This communication does not include details for the post-retirement medical plan. We suggest that you keep this communication with your other benefit materials so that you may refer to it later. **You do not need to take action as a result of this communication; it is for informational purposes only.**

Overview of Changes

After Dec. 31, 2017, your accrued benefit under the Piedmont Retirement Plan will be frozen and merged into the Duke Energy Retirement Cash Balance Plan (the "RCBP"). Beginning Jan. 1, 2018, you will accrue a pension benefit under the RCBP's **cash balance formula**. Your total pension benefit will be the sum of your frozen Piedmont Retirement Plan benefit as of Dec. 31, 2017 *plus* your new cash balance formula benefit beginning Jan. 1, 2018.

As part of this change, it is important to note the following:

- This new cash balance formula will look different than your current pension formula. Your current pension formula is based on your final average earnings and service at retirement. The new cash balance formula is an "account-based" formula; your benefit is based on pay credits and interest credits added to a bookkeeping account.
- Even though the cash balance formula is expressed as an account, it is still a pension benefit and has the same protections as your current pension formula. Duke Energy is responsible for paying 100% of the cost of the cash balance account, and you do not make personal contributions to this account. Additionally, the cash balance account will not decrease in amount because it is not tied to the investment performance in the financial markets.
- Your Age 65 accrued benefit earned in the Piedmont Retirement Plan through Dec. 31, 2017 will remain intact and be frozen as of that date; it will not decrease as part of this change, but it will also not grow based on service or earnings after Dec. 31, 2017.

In addition to the changes to the pension plan, Duke Energy will provide you with the following enhancements to the Duke Energy Retirement Savings Plan ("RSP"), your 401(k) plan, beginning Jan. 1, 2018:

1. **Special three-year employer transition credit contribution** - You will receive an additional employer transition credit contribution to the RSP each pay period for a three-year transition period while you remain employed with Duke Energy through Dec. 31, 2020. These employer transition credit contributions are 100% paid by Duke Energy, and you do not have to make any personal contributions to the RSP in order to receive these contributions. Employer transition credit contributions are based on your years of vesting service as of Dec. 31, 2017 under the Piedmont Retirement Plan, as follows:
    - Less than 15 years 3% of pay
    - 15 – 24 years 4% of pay
    - 25 or more years 5% of pay

2. **Additional company match** – Duke Energy will provide an opportunity to earn an additional 1% match on eligible pay that you contribute to the RSP on a before-tax and/or Roth basis for a total matching contribution opportunity of 6% of eligible pay. This match opportunity is <u>not</u> limited to a three-year transition period as is the case for the employer transition credit contributions noted in (1) above; in other words, it is part of the RSP formula available to you beginning Jan. 1, 2018 as a Duke Energy employee.

More detailed information about the pension changes follows in the chart starting on page 2. To help you understand the impact of these changes, examples of how the pension plan changes may affect future benefits

of sample employees are provided starting on page 5. Keep in mind that these are examples only. The impact to your future pension benefit will depend on factors such as your age, service, pay, and the date you start receiving your pension benefit.

If you have questions about the pension plan or this notice, call HR Direct at 800.521.0802 for assistance. After Jan. 1, 2018, you can contact the Duke Energy MyHR™ Service Center at 888.465.1300 for information and help. Also, in February 2018, you can access *Your Benefits Resources*™ 24/7 for personalized benefits information and self-service transactional tools such as creating pension benefit estimates.

Pension Formula Summary and Changes

The chart below outlines some of the key features of the pension formula, including those that are changing and others that are remaining the same.

<table>
<tr><th>Plan Feature</th><th>Under the Current Provisions
(PNG)</th><th>Under the New Formula Provisions
(Starting Jan. 1, 2018)</th><th>Impact/Additional Information</th></tr>
<tr>
<td>Benefit formula</td>
<td>
Final average pay formula:

Greater of (a) + (b), or (c):

a) The accrued benefit under the plan in effect Dec. 31, 2007 (Dec. 31, 2008 for Nashville union)

PLUS

b) 1.2% x Average Pay[1] + 0.5% x Average Pay[1] above Social Security Covered Compensation, multiplied by Benefit Service[2] earned after 2007 (2008 for Nashville union); only Benefit Service[2] up to 35 years is counted in this formula

- OR -

c) 1.2% x Average Pay[1] + 0.5% x Average Pay[1] above Social Security Covered Compensation, multiplied by Benefit Service[2]; only Benefit Service[2] up to 35 years is counted in this formula

• Former NCNG and Progress Energy participants have a portion of their legacy benefit earned under a different formula than what is described above.

[1]Average Pay means the average of your 5 highest years (60 consecutive months) of pension eligible pay within your last 10 calendar years of employment.

[2]Benefit Service generally includes your completed years and months of employment. Special rules apply for employees who were part of certain acquisitions.
</td>
<td>
Cash balance formula:

Account-based formula with Pay Credits and Interest Credits added each month.

Pay Credits include both a Basic Pay Credit and an Excess Pay Credit.

The amount of the Basic Pay Credit added each month is based on your age and service[3] at the beginning of the year:

<table>
<tr><th>Age + Service (Points)[4]</th><th>Percent of Pensionable Pay Credited to Your Pension Account each Month</th></tr>
<tr><td>34 or less</td><td>4.0%</td></tr>
<tr><td>35 – 49</td><td>5.0%</td></tr>
<tr><td>50 – 64</td><td>6.0%</td></tr>
<tr><td>65 or more</td><td>7.0%</td></tr>
</table>
The amount of the Excess Pay Credit added each month is equal to 4% of Pensionable Pay above the Social Security Wage Base ($128,700 in 2018).

Interest Credits are added each month based on an annual effective fixed rate of 4%.

[3] Service generally includes your completed years and months of employment, including service with Nashville Gas, North Carolina Natural Gas, Progress Energy, Gaffney, and Reidsville.

[4] Your Points are generally equal to the sum of your age and years of applicable service as of Jan. 1 of the plan year, expressed in complete years.
</td>
<td>
Putting it all together:

Your total retirement benefit will be the sum of:

• Your final average pay formula benefit that is frozen as of Dec. 31, 2017[5]

plus

• Your new cash balance formula benefit for service and pay earned beginning Jan. 1, 2018.

The actual impact of the formula change to you will vary based on your pensionable pay, age, service, date of termination or retirement, and lump sum factors at time of termination.

[5] Your final average pay benefit is "frozen" as of Dec. 31, 2017, which means that it is calculated based on your Average Pay and Benefit Service as of Dec. 31, 2017. Average Pay and Benefit Service will not increase beyond Dec. 31, 2017. Former NCNG and Progress Energy participants have a portion of their legacy benefit earned under a different formula.
</td>
</tr>
</table>

Plan Feature	Under the Current Provisions (PNG)	Under the New Formula Provisions (Starting Jan. 1, 2018)	Impact/Additional Information
How and when benefits are paid	• Normal retirement benefit is payable at age 65 as an annuity or equivalent lump sum. Other optional annuity forms are available. • Early retirement benefit is generally available as early as age 55 if you have at least 10 years of service. • Benefit is payable in a lump sum or annuity forms after employment ends, regardless of age. • The normal form of payment for married individuals is a 50% Joint and Survivor Annuity.	• Benefit is a lump sum equal to account balance at benefit commencement date. Benefit can be paid at any age after termination. • Benefit is also payable in annuity forms which are the actuarial equivalent of the account balance at benefit commencement date. • The normal form of payment for married individuals is a 100% Joint and Survivor Annuity.	• The current formula provides for early retirement subsidies for early retirement. The cash balance formula benefit is based on the account balance at benefit commencement date and does not include early retirement subsidies. • Beginning Jan. 1, 2018, for your total retirement benefit, the normal form of payment for married participants will be a 100% Joint and Survivor Annuity.
Pensionable pay considered in calculating benefits	Generally, pensionable pay is based on total pay, including base pay, overtime and bonus payments. If you are represented by one of the Company's bargaining units, your pensionable pay is generally the same as above, except for certain historical periods where pensionable pay included only base pay, and excluded overtime and bonuses. Pensionable pay is subject to pay limits specified by the IRS ($275,000 for 2018).	Generally, pensionable pay is based on total pay, including base pay, overtime and bonus payments. Pensionable pay is subject to pay limits specified by the IRS ($275,000 for 2018).	• The definition of pensionable pay is generally the same under the Current and New Provisions.
Disability benefits	If you have at least five years of Vesting Service and become disabled during your employment, you generally will continue to accrue in your final average pay benefit from date of disability to age 65. Your pension accrual will be similar to what you would have earned if you had continued employment with the Company, based on your rate of pay at the time disability is approved.	You are 100% vested in your cash balance account upon becoming disabled. Your disability event is otherwise treated the same as any other termination of employment. You can elect to receive your cash balance account benefit or leave it in the RCBP. If left in the RCBP, your account will earn Interest Credits, but not Pay Credits.	• If you are already accruing disability benefits in the Piedmont Retirement Plan or are in your disability waiting period on Dec. 31, 2017, your benefit will be based on the Current Provisions. In other words, your final average pay benefit will not be frozen on Dec. 31, 2017, but you will not earn any benefits under the new cash balance formula. However, if you return to work, after more than one year on a disability leave, your final average pay benefit will be frozen at that time, you will participate in the employer retirement contributions under the terms of the Duke Energy RSP, and you will not be eligible for future benefits from the RCBP. If you return after less than one year on disabilty leave, your final average pay benefit will be frozen and you will be transitioned to the RCBP as described in this notice, but effective on the date you return. • All employees who begin their disability waiting period on or after Jan. 1, 2018 will receive the disability benefit under the New Provisions.

Plan Feature	Under the Current Provisions (PNG)	Under the New Formula Provisions (Starting Jan. 1, 2018)	Impact/Additional Information
Pre-retirement survivor benefits	If you are vested and die prior to starting benefits, payments are made to your beneficiary(ies) under the 50% Joint and Survivor annuity option at your death, or can be payable in an equivalent immediate lump sum. Spouse beneficiaries may defer payment until Dec. 31 of the year in which you would have attained age 70½. You do not need to be married at the time of death to be eligible for death benefits. However, if you are married, you may only designate a beneficiary other than your spouse with written, notarized spousal consent.	If you die prior to starting benefits, your spouse or other designated beneficiary will receive a lump sum of your full cash balance account following your death. Spouse beneficiaries may defer payment until Dec. 31 of the year in which you would have attained age 70½, and your cash balance account will continue to earn Interest Credits. An annuity option also is available to spouse beneficiaries. You do not need to be married at the time of death to be eligible for death benefits. However, if you are married, you may only designate a beneficiary other than your spouse with written, notarized spousal consent.	Your total pre-retirement survivor benefit will be the sum of: • Your survivor benefit under the final average pay formula that is frozen as of Dec. 31, 2017 *plus* • The death benefit under the new cash balance formula beginning Jan. 1, 2018. • Under the cash balance formula, non-spouse beneficiaries may only receive a lump sum. • Final average pay formula survivor benefit will be based on the 100% Joint and Survivor annuity option. This is an enhancement from what is offered under the Current Provisions. • If you are married, you may only designate a beneficiary other than your spouse with written, notarized spousal consent.
Rehires	Rehired employees after the plan closure date of January 1, 2008 (or January 1, 2009 for Nashville union participants) are not allowed to earn additional benefits in the pension plan upon rehire. Their benefits are frozen at time of termination.	Rehired employees are not allowed to earn additional benefits in the pension plan upon rehire. Their benefits are frozen at time of termination.	Rehired employees on or after Jan. 1, 2018 will not be allowed to earn additional benefits in the pension plan upon rehire, and instead will be eligible for employer contributions under the terms of the Duke Energy RSP.
How benefits are funded	Paid for in full by Duke Energy	Paid for in full by Duke Energy	No change – the cash balance formula is part of a pension arrangement, where the company pays 100% of the cost.
Who bears the investment risk	Duke Energy	Duke Energy	No change – the cash balance formula is part of a pension arrangement, where the company bears the investment risk.
Pension Benefit Guaranty Corporation ("PBGC") Insurance Protection	PBGC insurance protection applies.	PBGC insurance protection applies.	No change – the cash balance formula is part of a pension arrangement protected by the PBGC.

Examples

Now that you have a better idea of how your pension formula will change, let's compare some benefit calculations under the Current Provisions and New Provisions effective Jan. 1, 2018, including the enhancements that are being made to the RSP. These examples show the potential benefits both before and after the changes for employees at various combinations of age, service and pay. While the employees in the following examples are fictitious, the benefit calculations are based on the actual provisions of the pension plan and the assumptions described below:

- Each employee's pensionable pay was assumed to increase at a rate of 3% each year
- Social Security Covered Compensation and Wage Base are assumed to increase 3% each year and qualified pay limits are assumed to increase 2.25% each year
- Each employee was assumed to defer 6% of pay in the RSP (i.e., enough to maximize his/her company match under the RSP beginning Jan. 1, 2018)
- The investment of RSP account balances is assumed to grow 6% annually
- Lump-sum benefits were converted to annuities using a current interest rate assumption and standard mortality table required by law.

Employee RSP contributions, employer matching contributions (other than the incremental 1% additional match opportunity) and social security benefits are not included in the benefit projections shown in the examples.

Keep in mind that different assumptions would produce different results. Remember, these are examples only. The impact of the pension formula changes on your pension benefit will depend on your age, service, pay, and the date you start your pension benefit. Although for most employees, the changes will result in a reduction in their rate of future benefit accrual, it is important to remember that the changes are being made to minimize differences among groups of employees at Duke Energy. It is not sustainable for Duke Energy to maintain legacy programs, and it would make it difficult to facilitate career development and job transfer opportunities across the company if programs were different.

Example 1

Meet Barry. Barry was hired right before the plan closed participation to new entrants in 2008. He is 35 years old with 10 years of service, and his pay is $40,000. The following table shows what Barry's benefit would be today, three years from today, at age 55, and at age 65, based on how he elects to receive his benefit (e.g., monthly annuity or lump sum).

If Barry chooses to retire at age 65 and take his pension benefit as a single life annuity, he will receive $1,678 per month for the rest of his life. He would also earn the equivalent of $390 per month, payable for the rest of his life, from the additional enhancements to the RSP that Duke Energy has provided. This includes i) employer transition credit contributions equal to 3% of pay from Jan. 1, 2018 to Dec. 31, 2020 and ii) an extra 1% of pay match opportunity beginning Jan. 1, 2018 that continues until he retires.

Retiring at age 65, but selecting the lump-sum benefit, Barry would receive a total pension of $288,535, and he would also be entitled to an additional benefit from enhancements to the RSP of $66,995.

As reflected in the chart on the next page and based on a number of assumptions described above, Barry's total benefit three years from now is projected to be *larger* than it would have been without the pension formula change, due to the enhancements to the RSP. However, in later years, his total benefit is projected to be *smaller* than it would have been without the pension formula change. In all cases, as shown in the chart, his pension benefit increases as he continues employment with the company.

Example 1 (continued)

	Accrued Monthly Benefit Payable as an Immediate Single Life Annuity				Accrued Benefit Payable as a Lump Sum			
Age at Termination	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP[1]	Total Benefit With Changes	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP	Total Benefit With Changes
35	$62	$62	$0	$62	$15,998	$15,998	$0	$15,998
38	$102	$99	$22	$121	$25,851	$24,951	$5,559	$30,510
55	$1,186	$706	$148	$854	$220,233	$142,793	$31,036	$173,829
65	$3,206	$1,678	$390	$2,068	$551,362	$288,535	$66,995	$355,530

Example 2

Meet Sarah. Sarah is in the middle of her career and wants to plan for retirement. She is 45 years old with 15 years of service, and her pay is $100,000. The following table shows what Sarah's benefit would be today, three years from today, at age 55, and at age 65, based on how she elects to receive her benefit (e.g., monthly annuity or lump sum).

If Sarah chooses to retire at age 65 and take her pension benefit as a single life annuity, she will receive $3,093 per month for the rest of her life. She would also earn the equivalent of $506 per month, payable for the rest of her life, from the additional enhancements to the RSP that Duke Energy has provided. This includes i) employer transition credit contributions equal to 4% of pay from Jan. 1, 2018 to Dec. 31, 2020 and ii) an extra 1% of pay match opportunity beginning Jan. 1, 2018 that continues until she retires.

Retiring at age 65, but selecting the lump-sum benefit, Sarah would receive a total pension benefit of $531,885, and she would also be entitled to an additional benefit from enhancements to the RSP of $86,946.

As reflected in the chart below and based on a number of assumptions described above, Sarah's total benefit three years from now is projected to be *larger* than it would have been without the pension formula change, due to the enhancements to the RSP. However, in later years, her total benefit is projected to be *smaller* than it would have been without the pension formula change. In all cases, as shown in the chart, her pension benefit increases as she continues employment with the company.

	Accrued Monthly Benefit Payable as an Immediate Single Life Annuity				Accrued Benefit Payable as a Lump Sum			
Age at Termination	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP[1]	Total Benefit With Changes	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP	Total Benefit With Changes
45	$407	$407	$0	$407	$96,770	$96,770	$0	$96,770
48	$625	$581	$75	$656	$143,998	$133,888	$17,372	$151,260
55	$1,838	$1,318	$175	$1,493	$341,405	$255,714	$36,695	$292,409
65	$6,152	$3,093	$506	$3,599	$1,058,027	$531,885	$86,946	$618,831

[1] For illustration purposes only. Annuity benefits are not payable from the RSP.

Example 3

Meet Margaret. Margaret has spent nearly all of her career with Piedmont Natural Gas and is also starting to plan for retirement. She is 50 years old with 25 years of service, and her pay is $80,000. The following table shows what Margaret's benefit would be today, three years from today, at age 55, and at age 65, based on how she elects to receive her benefit (e.g., monthly annuity or lump sum).

If Margaret chooses to retire at age 65 and take her pension benefit as a single life annuity, she will receive $2,885 per month for the rest of her life. She would also earn the equivalent of $300 per month, payable for the rest of her life, from the additional enhancements to the RSP that Duke Energy has provided. This includes i) employer transition credit contributions equal to 5% of pay from Jan. 1, 2018 to Dec. 31, 2020 and ii) an extra 1% of pay match opportunity beginning Jan. 1, 2018 that continues until she retires.

Retiring at age 65, but selecting the lump-sum benefit, Margaret would receive a total pension benefit of $496,106 under the new pension formula, and she would also be entitled to an additional benefit from enhancements to the RSP of $51,679.

As reflected in the chart below and based on a number of assumptions described above, Margaret's total benefit three years from now is projected to be *larger* than it would have been without the pension formula change, due to the enhancements to the RSP. However, in later years, her total benefit is projected to be *smaller* than it would have been without the pension formula change. In all cases, as shown in the chart, her pension benefit increases as she continues employment with the company.

	Accrued Monthly Benefit Payable as an Immediate Single Life Annuity				Accrued Benefit Payable as a Lump Sum			
Age at Termination	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP[1]	Total Benefit With Changes	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP	Total Benefit With Changes
50	$773	$773	$0	$773	$173,989	$173,989	$0	$173,989
53	$1,075	$1,019	$77	$1,096	$232,463	$220,249	$16,677	$236,926
55	$1,522	$1,352	$99	$1,451	$282,719	$254,930	$20,676	$275,606
65	$4,115	$2,885	$300	$3,185	$707,796	$496,106	$51,679	$547,785

Example 4

Meet Roger. Roger is nearing retirement and already has reached the service cap of 35 years under the Piedmont Retirement Plan final average pay formula. He is 60 years old with 35 years of service, and his pay is $85,000. The following table shows what Roger's benefit would be today, three years from today, and at age 65, based on how he elects to receive his benefit (e.g., monthly annuity or lump sum).

If Roger chooses to retire at age 65 and take his pension benefit as a single life annuity, he will receive $3,015 per month for the rest of his life. He would also earn the equivalent of $128 per month, payable for the rest of his life, from the additional enhancements to the RSP that Duke Energy has provided. This includes i) employer transition credit contributions equal to 5% of pay from Jan. 1, 2018 to Dec. 31, 2020 and ii) an extra 1% of pay match opportunity beginning Jan. 1, 2018 that continues until he retires.

Retiring at age 65, but selecting the lump-sum benefit, Roger would receive a total pension benefit of $518,569, and he would also be entitled to an additional benefit from enhancements to the RSP of $21,968.

[1] For illustration purposes only. Annuity benefits are not payable from the RSP.

As reflected in the chart below and based on a number of assumptions described above, the reduction in Roger's benefit due to the pension formula change is largely offset by the enhancement to the RSP. In all cases, as shown below in the chart, his pension benefit increases as he continues employment with the company.

	Accrued Monthly Benefit Payable as an Immediate Single Life Annuity				Accrued Benefit Payable as a Lump Sum			
Age at Termination	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP[1]	Total Benefit With Changes	If No Changes Were Made to the Pension Formula	With Changes to the Pension Formula	Additional Benefit From Enhancements to the RSP	Total Benefit With Changes
60	$2,217	$2,217	$0	$2,217	$379,889	$379,889	$0	$379,889
63	$2,809	$2,682	$98	$2,780	$480,838	$460,124	$17,719	$477,843
65	$3,254	$3,015	$128	$3,143	$559,583	$518,569	$21,968	$540,537

Important Legal Notice

This document contains selected highlights of Duke Energy's employee benefits plans. If any statement herein, or any other communication, conflicts with applicable plan documents, the plan documents will govern. Duke Energy retains the right to amend, modify or terminate its benefits plans in any respect and at any time, and neither its benefits plans nor your plan participation will be considered a contract for future employment.

This notice, in connection with other information provided to you, is being distributed pursuant to Section 204(h) of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), which requires that participants be notified in writing of any changes to the Piedmont Retirement Plan that may result in a reduction in rate of future benefit accruals, and to provide a brief explanation of the change.

Because of the changes to the Piedmont Retirement Plan, there is a potential that benefits you earn under the Piedmont Retirement Plan (and the RCBP following the merger of the Piedmont Retirement Plan into the RCBP) may not be as great as those that would have been earned had you continued to earn benefits under the Piedmont Retirement Plan prior to the amendment.

The notice is based on information and assumptions in effect at the time of the notice (e.g., assumed pay increases, assumptions on interest rates and standard life expectancy tables, etc.). Duke Energy does not undertake any obligation to update or make any revisions to this notice, and no such revisions to this notice will be issued to reflect any changes, including, but not limited to, changes in policies, the adoption of plan amendments, or any other events or circumstances occurring after this notice is provided.

[1] For illustration purposes only. Annuity benefits are not payable from the RSP.

Important Notice concerning your rights under the Piedmont Natural Gas Company, Inc. 401(k) Plan (the "Piedmont 401(k) Plan"), the Piedmont Natural Gas Company, Inc. Money Purchase Pension Plan (the "Piedmont MPPP") and the Duke Energy Retirement Savings Plan (the "RSP")

This Notice is to inform you that your Piedmont 401(k) Plan account and/or Piedmont MPPP account will merge into the RSP after the close of business on Dec. 31, 2017, and it includes important information and deadlines that may require you to take action. The Piedmont 401(k) Plan and Piedmont MPPP will transition from their current service provider, Wells Fargo, to a new service provider, Fidelity Investments® ("Fidelity").

How to use this Guide

Follow these steps to make the most of the transition.

1. **Understand the key dates and deadlines**
   Read *Key dates and deadlines* beginning on page 3 to understand the calendar of events.

2. **Know what's changing**
   Read *What's changing* beginning on page 8 to understand how the Piedmont 401(k) Plan and Piedmont MPPP will transition. You should read this guide in conjunction with the enclosed RSP Summary Plan Description ("SPD") and the 2017 Investment Funds Summaries booklet to understand the features and investment funds available under the RSP.

3. **Take any needed actions**
   See *Actions to consider* on page 15 for steps that can help you plan for the changes.

For those who currently participate in the Piedmont MPPP, a 204(h) notice also is enclosed to advise you of future changes to that plan. Those who currently participate in the Retirement Plan of Piedmont Natural Gas Company, Inc. (the "Piedmont Retirement Plan") will receive a 204(h) notice in a separate mailing.

If you have questions about the RSP or this Notice, including the transition and the blackout period discussed on page 2, contact Fidelity's Duke Energy Customer Service Line at **800.376.4015** beginning Nov. 7, 2017. Representatives are available from 8:30 a.m. to 8:30 p.m. Eastern time (ET) on business days, except New York Stock Exchange ("NYSE") holidays.

This Notice serves as a supplement to your summary plan description for each of the plans, and constitutes part of a Section 10(a) Prospectus for the RSP covering securities that have been registered under the Securities Act of 1933. Note that certain information in this Notice (*e.g.*, contributions) does not apply to former employees,

beneficiaries and alternate payees. Also, if you are not a participant in both the Piedmont 401(k) Plan and Piedmont MPPP, the information about the plan in which you do not participate does not apply to you. Please keep a copy of this Notice as a reference.

You have a new plan: the RSP

The Piedmont 401(k) Plan and Piedmont MPPP will merge into the RSP after the close of business on Dec. 31, 2017.

As a result, and as explained further in this guide, a blackout period will take place in the plans. The blackout period is expected to begin at 4 p.m. ET on Dec. 7, 2017, and end during the week beginning Jan. 14, 2018; however, not all transactions will be restricted during the entire blackout period. Please read the chart showing key dates to determine the dates when specific transactions will be restricted in the Piedmont 401(k) Plan and/or Piedmont MPPP and the RSP.

Finally, as part of the transition, the investment funds available to you will change. After the close of market on Dec. 29, 2017, your fund balances in the Piedmont 401(k) Plan and/or Piedmont MPPP will transfer to the RSP based on the transition described in this guide.

Blackout period

It is important to note that merging the Piedmont 401(k) Plan and Piedmont MPPP into the RSP will require some behind-the-scenes work. As a result, you temporarily will be unable to complete certain transactions in the plans, including (as applicable) any loan, withdrawal, or distribution transactions, exchanges (transfers) between investment funds, changes to your future contribution percentages and changes to direct how your future contributions will be invested. This period, during which you will be unable to exercise these rights otherwise available under the plans, is called a “blackout period.”

Please see *Key dates and deadlines* for details about the activities that will be affected during the transition. We encourage you to carefully consider how this blackout period may affect your retirement planning, as well as your overall financial plan.

Please note the following important information:

For certain portions of the blackout period (as described in the chart below), you will be unable to direct or diversify the assets held in your Piedmont 401(k) Plan and/or Piedmont MPPP and RSP account for amounts transferred from the Piedmont 401(k) Plan and/or Piedmont MPPP. For this reason, it is very important that you review and consider the appropriateness of your current investments in light of your inability to direct or diversify those investments during the blackout period.

For your long-term retirement security, you should give careful consideration to the importance of a well-balanced and diversified portfolio, taking into account all of your assets, income and investments.

Key dates and deadlines

Review the following table to understand how account activities will be affected during the blackout period. Plan now for the transition and any transactions that you would like to make before the blackout period begins.

Date	Piedmont 401(k) Plan, Piedmont MPPP and RSP activities	What this means to you
Dec. 7, 2017 (after close of business)	**Blackout period begins for qualified domestic relations order ("QDRO") and beneficiary account set-up under the Piedmont 401(k) Plan and Piedmont MPPP.** This is the last day to submit QDRO or beneficiary documentation to Wells Fargo to establish an account for a QDRO alternate payee or beneficiary before the blackout period. The blackout on submitting QDRO and beneficiary documentation to Wells Fargo is expected to begin after the close of the NYSE, generally 4 p.m. ET, on Dec. 7, 2017.	**Want to set up a QDRO or beneficiary account before the blackout period?** Documentation must be submitted to Wells Fargo before the close of the NYSE, generally 4 p.m. ET to have a QDRO alternate payee or beneficiary account established before the blackout period. The next opportunity to request these transactions will be when the blackout period ends, scheduled during the week beginning Jan. 14, 2018. Call Wells Fargo at **800.SAVE123** for more information regarding submitting documentation.
Dec. 14, 2017 (before close of business)	**Last day to request and/or submit documentation for the following transactions for your Piedmont 401(k) Plan and Piedmont MPPP account.** • Submit hardship distribution documentation for the Piedmont 401(k) Plan • Submit loan payoff checks for the Piedmont 401(k) Plan • Submit home loan documentation for the Piedmont 401(k) Plan • Submit required minimum distribution (for participants who have attained age 70½) from the	**Want to request and/or submit documentation for one of these transactions before the blackout period?** You must submit your documentation to Wells Fargo before the close of the NYSE, generally 4 p.m. ET, to have these transactions completed before the blackout begins. Call Wells Fargo at **800.SAVE123** for more information regarding submitting documentation. Your next opportunity to request these transactions will be when the

Date	Piedmont 401(k) Plan, Piedmont MPPP and RSP activities	What this means to you
	Piedmont 401(k) Plan • Submit documentation for a distribution from the Piedmont MPPP • Submit rollover contribution check and required documentation for the Piedmont 401(k) Plan	blackout period ends, scheduled during the week beginning Jan. 14, 2018.
Dec. 21, 2017 (before close of business)	**Last day to request the following transactions from your Piedmont 401(k) Plan.** • Request a general loan from the Piedmont 401(k) Plan • Request a distribution or withdrawal (if eligible) from the Piedmont 401(k) Plan	**Want to request one of these transactions before the blackout period?** Call Wells Fargo at **800.SAVE123** or log on to wellsfargo.com before the close of the NYSE, generally 4 p.m. ET, to request any of these transactions. Your next opportunity to request these transactions will be when the blackout period ends, scheduled during the week beginning Jan. 14, 2018.
Dec. 22, 2017 (before close of business)	**Last day to request the following transactions from your Piedmont 401(k) Plan and Piedmont MPPP account.** • Request changes to the investment of contributions or request an exchange ("transfer") among investment funds for the Piedmont 401(k) Plan and Piedmont MPPP* • Request changes to contribution rates or beneficiary elections for the Piedmont 401(k) Plan and Piedmont MPPP* • All other transactions for your Piedmont 401(k) Plan and Piedmont MPPP account	**Want to request one of these transactions before the blackout period?** Call Wells Fargo at **800.SAVE123** or log on to wellsfargo.com before the close of the NYSE, generally 4 p.m. ET, to request any of these transactions. Your next opportunity to request these transactions will be when the blackout period ends, during the week ending Jan. 6, 2018 for certain transactions and during the week beginning Jan. 14, 2018 for all transactions.

Date	Piedmont 401(k) Plan, Piedmont MPPP and RSP activities	What this means to you
Dec. 29, 2017	**Piedmont 401(k) Plan and Piedmont MPPP account valuation.** Your Piedmont 401(k) Plan and/or Piedmont MPPP account balance will be valued after the close of the NYSE, generally 4 p.m. ET, on Dec. 29, 2017.	**Impact to investment fund balances.** Your Piedmont 401(k) Plan and/or Piedmont MPPP account balance will be invested in your current investment funds until the close of the NYSE.
Jan. 2, 2018	**Money transfers.** Your Piedmont 401(k) Plan's and/or Piedmont MPPP's assets, valued after the close of the NYSE, generally 4 p.m. ET on Dec. 29, 2017, are scheduled to be transferred to the RSP's investment funds.	**Want to know how the Piedmont 401(k) Plan's and/or Piedmont MPPP's investment funds will transfer?** Read *Mapping of current investment funds* on page 7 to understand how investment funds will transfer. The Piedmont 401(k) Plan's and Piedmont MPPP's assets will be invested in the RSP's investment funds on Jan. 2, 2018. Contributions with respect to the Dec. 29, 2017 catch-up payroll will be invested in the RSP on, or as soon as practicable after, Jan. 2, 2018.

Date	Piedmont 401(k) Plan, Piedmont MPPP and RSP activities	What this means to you
During the week ending Jan. 6, 2018	**RSP Blackout and expected end of blackout period for certain transactions** The blackout generally continues under the RSP for your Piedmont 401(k) Plan's and/or Piedmont MPPP's assets. However, during the week ending Jan. 6, 2018, the following transactions are expected to be available (the "RSP transactions"): • Request changes to contributions, dividend or beneficiary elections* • Request changes to the investment of contributions* • Request an exchange ("transfer") among investment funds for your RSP account balance other than the amount attributable to your Piedmont 401(k) Plan's and/or Piedmont MPPP's assets.** • Request a distribution, withdrawal or loan (if eligible) for your RSP account balance other than the amount attributable to your Piedmont 401(k) Plan's and/or Piedmont MPPP's assets.**	**Want to name your beneficiary, or change future contributions or investment of contributions, or request certain other transactions?** When RSP transactions become available during the week ending Jan. 6, 2018, you can request the RSP transactions by logging on to **401k.com** or calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**. Representatives are available Monday through Friday (excluding NYSE holidays), between 8:30 a.m. and 8:30 p.m. ET.

Date	Piedmont 401(k) Plan, Piedmont MPPP and RSP activities	What this means to you
During the week <u>beginning</u> Jan. 14, 2018	**Blackout period expected to end.** All transactions for the transferred Piedmont 401(k) Plan and Piedmont MPPP assets are expected to be available under the RSP. You can then: • Request a distribution, withdrawal or loan (if eligible) for your entire RSP account • Request an exchange ("transfer") among investment funds for your entire RSP account • Request a statement of your entire RSP account	**Want to check your investments or request transactions in your RSP account?** When the blackout period ends, you can view your account and request transactions or an account statement by logging on to **401k.com** or calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**. Representatives are available Monday through Friday (excluding NYSE holidays), between 8:30 a.m. and 8:30 p.m. ET.

*See the "What's changing" section for important information about the contribution, beneficiary and investment elections that will apply under the RSP.

**Contributions with respect to the Dec. 29, 2017 catch-up payroll will be invested in the RSP on, or as soon as practicable after, Jan. 2, 2018, and will be considered part of your RSP account that is <u>not</u> attributable to your Piedmont 401(k) Plan's and/or Piedmont MPPP's assets.

The effective date of the changes described above and the end of the blackout period depend upon the accurate and timely transfer of data. To ensure accurate data transfer, the delivery of services described here could be delayed. You can determine whether the blackout period has started or ended by calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**.

Note that any paycheck deductions for contributions to either the Piedmont 401(k) Plan or the RSP and applicable company matching contributions, will occur as scheduled for pay periods ending during the blackout period. **As a reminder, exempt (salaried) employees will be paid on a semi-monthly frequency beginning in January 2018.** A catch-up payroll for exempt (salaried) employees will be paid on Dec. 29, 2017 for the two-week period ending Dec. 31, 2017. Contributions with respect to the Dec. 29, 2017 catch-up payroll will be invested in the RSP on, or as soon as practicable after, Jan. 2, 2018.

If you have an outstanding loan under the Piedmont 401(k) Plan as of Dec. 31, 2017, the loan balance will transfer to the RSP and the loan maintenance fee described on

page 8 of the Investment Funds Summaries will apply. Additionally, if you are an exempt (salaried) employee, effective Jan. 1, 2018, any outstanding loan balance will be re-amortized and loan deductions will be made based on a semi-monthly pay frequency. No loan repayment deductions will be taken from the Dec. 29, 2017 catch-up payroll for exempt (salaried) employees.

Recordkeeping and trustee services for the RSP are provided by Fidelity Investments. Starting Nov. 7, 2017, if you have any questions, please call Fidelity's Duke Energy Customer Service Line at **800.376.4015**, Monday through Friday (excluding New York Stock Exchange holidays), from 8:30 a.m. to 8:30 p.m. ET, to speak with a service center representative.

What's changing

Mapping of current investment funds

Your existing Piedmont 401(k) Plan and/or Piedmont MPPP fund balances will transfer according to the following mapping table after the close of market on Dec. 29, 2017. Your Piedmont 401(k) Plan investment elections for future contributions will also transfer according to the following table and apply to all RSP contributions, employee and employer. However, if you are currently a participant in the RSP, your current RSP elections for future contributions will govern and not your Piedmont 401(k) elections for future contributions. Also note that your Piedmont MPPP investment elections for future contributions will not transfer to the RSP under any circumstances. You will find details on the RSP's investment funds in the enclosed 2017 Investment Funds Summaries booklet.

If you have a balance in Piedmont 401(k) Plan and/or Piedmont MPPP as of 4 p.m. ET on Dec. 29, 2017 or are directing contributions to the Piedmont 401(k) Plan as of 4 p.m. ET on Dec. 29, 2017		**Your account balances and Piedmont 401(k) contribution election will map to this RSP investment fund**
Wells Fargo Enhanced Stock Market Fund Harbor Capital Appreciation Institutional Fund Dodge & Cox Stock Fund	→	U.S. Equity S&P 500 Index Fund

If you have a balance in Piedmont 401(k) Plan and/or Piedmont MPPP as of 4 p.m. ET on Dec. 29, 2017 or are directing contributions to the Piedmont 401(k) Plan as of 4 p.m. ET on Dec. 29, 2017		Your account balances and Piedmont 401(k) contribution election will map to this RSP investment fund
JPMorgan Mid-Cap Value Institutional Fund Victory Munder Mid-Cap Core Growth Fund Victory Small Company Opportunity Fund I T. Rowe Price Horizons Fund		U.S. Equity Small/Mid Cap Blend Fund
Wells Fargo Stable Return Fund		Stable Value Fund
American Century Inflation-Adjusted Bond Institutional Fund Dodge & Cox Income Fund		Fixed Income Blend Fund
Vanguard Total International Stock Index Fund I American Funds EuroPacific Growth Fund R6		Non-U.S. Equity Blend Fund
American Funds – American Balanced Fund Capital Preservation Model Portfolio Fund Conservative Model Portfolio Fund All Weather Model Portfolio Fund Growth Model Portfolio Fund Aggressive Model Portfolio Fund		Target Retirement Date Fund closest to the year you will reach age 65*

*Refer to the table at the bottom of page 47 of the enclosed 2017 Investment Funds Summaries booklet that shows the date of birth and retirement date range associated with each Target Retirement Date Fund. The Target Retirement Date Funds are the qualified default investment alternative ("QDIA") under the RSP. See the 2017 Investment Funds Summaries booklet and SPD for the RSP for more information on the QDIA.

The transfer of assets depends on the timely liquidation and delivery of assets. A delay may result in a change to the above-noted date.

Your RSP contributions

- The RSP allows employees to contribute on a before-tax, Roth and after-tax basis. **After-tax contributions are not matched.**

- **Your before-tax contributions election will transfer from your Piedmont 401(k) Plan to the RSP** (unless you are already a participant in the RSP with an election on file). If you wish to update your contribution rate, you can do so by 4 p.m. ET on Dec. 22, 2017 under the Piedmont 401(k) Plan or after RSP transactions become available during the week ending Jan. 6, 2018. Note that, if you have not made an election to contribute to the Piedmont 401(k) Plan by Dec. 22, 2017, you will need to make an election under the RSP to make contributions to the RSP (*i.e.*, automatic enrollment under the RSP will not apply to you). If you wish to update the type of contribution that you are making, you can do so after RSP transactions become available during the week ending Jan. 6, 2018. Under the RSP, you may save up to 75% of your eligible pay, in whole or half percentages, on a before-tax, Roth and/or after-tax basis, but the total you contribute to your RSP account cannot be more than 75% of your eligible pay, subject to the annual Internal Revenue Service ("IRS") limits. In 2017, the annual IRS limit for before-tax and/or Roth contributions is $18,000.

  If your before-tax contribution election under the Piedmont 401(k) Plan is suspended at 4 p.m. ET on Dec. 22, 2017, you will need to make an election under the RSP to recommence your contributions after the suspension period.

- **If you will be age 50 or over at any time in a plan (calendar) year**, you are eligible to make before-tax and Roth "catch-up" contributions up to the IRS catch-up contribution limit ($6,000 for 2017). Since your company matching formula is a 100% match up to 6% of eligible pay, you can contribute $24,000 (for 2017) ratably over the year and the first 6% of your compensation contributed each pay period will be matched on each paycheck.

  For additional information about before-tax, Roth and after-tax contributions, please refer to page 4 of the enclosed SPD.

RSP employer matching contributions

- Each pay period, the company will match your before-tax and/or Roth contributions to the RSP, up to 6% of your eligible pay, subject to IRS limits. Note that after-tax contributions are not matched.

- The RSP includes a "true-up" feature for participants employed on the last day of the plan year (Dec. 31) who did not contribute at an even rate throughout the plan year and did not receive a full match as a result of contributing less than 6% for certain pay periods. For example, if, you are employed on the last day of the plan year and you made before-tax and/or Roth contributions of at least 6% of your eligible pay for the plan year, you will receive a true-up contribution after year-end, generally by Jan.

31, as needed for you to receive an aggregate matching contribution equal to 6% of your eligible pay for the plan year. The true-up contribution is subject to the applicable IRS and RSP limits for the plan year for which the true-up contribution applies. In no event will matching contributions be greater than the lesser of your eligible pay or the IRS compensation limit, multiplied by 6%.

RSP employer transition credit contributions

- If you are an active employee and participant under the Piedmont Retirement Plan on Dec. 31, 2017, beginning on Jan. 1, 2018 through Dec. 31, 2020, each pay period during which you are employed, the company will make employer transition credit contributions to your RSP account. Note that, effective Jan. 1, 2018, the Piedmont Retirement Plan will be merged into the Duke Energy Retirement Cash Balance Plan (the "RCBP"). See the RSP SPD for more information on the employer transition credit contributions.

RSP employer retirement contributions

- Beginning on Jan. 1, 2018, each pay period, the company will make employer retirement contributions to your RSP account of 4% of your eligible earnings if you are <u>not</u> an active participant in the RCBP, the successor to the Piedmont Retirement Plan. Note that contributions under the Piedmont MPPP formula will end as of Dec. 31, 2017. See the RSP SPD for more information on the employer retirement contributions.

RSP Eligible Earnings

- For your contributions, employer matching contributions, employer retirement contributions and employer transition credit contributions, eligible earnings generally include base pay plus overtime, unused vacation pay (when paid after termination of employment), most short-term incentive pay and lump sum merit pay. The amount you elect to save will be withheld automatically from your pay to the extent possible based on your eligible pay after other required paycheck deductions are taken.

RSP Auto-increase feature

The RSP has an auto-increase feature that permits you to have your RSP contributions increased each year automatically. You will have to elect the auto-increase feature after RSP transactions become available during the week ending Jan. 6, 2018 if you wish to have auto-increases apply to increase your contributions. Subject to IRS limits, you can choose to increase your RSP contributions by up to 2% every year, automatically. Auto-increases stop after your contributions reach 10%. You can opt into or out of this automatic increase feature at any time. No existing auto increase election in the Piedmont 401(k) Plan will transfer to the RSP.

RSP access to your savings – withdrawals and/or loans

Under certain conditions, you may take a withdrawal or loan from your RSP account (other than amounts attributable to the Piedmont MPPP, employer retirement contributions and employer transition credit contributions) while you work for Duke Energy. If you currently have an outstanding loan under the Piedmont 401(k) Plan, your loan will transfer to the RSP. The RSP permits up to two loans outstanding at a time, subject to IRS rules. If your pay frequency changes and you have an outstanding loan, your loan will be recalculated to reflect the updated pay schedule, resulting in a modest change in your loan payment amount. It follows that, if you are an exempt (salaried) employee, effective Jan. 1, 2018, any outstanding loan balance will be re-amortized and loan deductions will be made based on a semi-monthly pay frequency.

RSP Vesting

You are 100% vested in your contributions to the RSP and in employer transition credit contributions and employer matching contributions (including, effective Jan. 1, 2018, employer matching contributions previously made under the Piedmont 401(k) Plan). You become fully vested in employer retirement contributions and amounts attributable to the Piedmont MPPP upon three years of service or if you reach age 65, die or become disabled while employed. Satisfaction of the three-year vesting requirement for any non-vested Piedmont participants will be determined based on the sum of your actual Piedmont MPPP hours based vesting service on Dec. 31, 2017, actual RSP elapsed time vesting service beginning Jan. 1, 2018, and nine months of deemed vesting service provided on Dec. 31, 2017 for transition purposes.

You are eligible to take a distribution of your vested RSP account balance when your Duke Energy employment ends.

No safe harbor status

Unlike your current Piedmont 401(k) Plan, the RSP does not include a safe harbor formula under the IRS tax code. Because the RSP does not have a safe harbor formula, the RSP can contain certain features not available under the Piedmont 401(k) Plan, such as a true-up contribution for employees who are employed on the last day of the plan year. Note that it is expected that the RSP will pass IRS non-safe harbor discrimination testing without reducing contributions for highly compensated employees.

RSP Beneficiary Designations

Your online beneficiary elections generally **will not** transfer from your Piedmont 401(k) Plan or Piedmont MPPP to the RSP.

After RSP transactions become available during the week ending Jan. 6, 2018, you can elect your beneficiary designation under the RSP by logging on to 401k.com or calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**.

If you do not make a beneficiary designation under the RSP, the RSP default provisions will apply (i.e., your spouse will be your beneficiary, and if you have no spouse, then your estate will be your beneficiary).

For Piedmont MPPP account balances transferred to the RSP, the following special rule will apply to your entire account under the RSP. If you designate a non-spouse beneficiary under the RSP while employed before the year in which you attain age 35, the designation expires on the first day of the year in which you attain age 35. You can again designate the same or another beneficiary (with spousal consent, as applicable) on or after the first day of the year in which you attain age 35 (or at any time after you are no longer employed).

Duke Energy Common Stock Fund dividend reinvestment elections

If you invest a portion of your RSP account in the Duke Energy Common Stock Fund, you may elect to receive Duke Energy common stock dividends attributable to your fund balance paid directly to you in cash or to have the dividends reinvested in the fund. If you make no election, the default is to have dividends reinvested in the fund. You may elect to change your dividend election at any time during the year, effective with the next dividend payment, with the exception of elections made during the 10-business-day period prior to the ex-dividend date. The ex-dividend date is generally 30 days prior to the dividend payment date. Refer to the Participant Fees section on page 8 of the enclosed Investment Funds Summaries booklet, which describes the RSP's fees associated with the payment of cash dividends. After RSP transactions become available d**uring the week ending Jan. 6, 2018**, you can view and update your dividend election by logging on to **401k.com** or calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**. Note that contribution elections and transfers to the Duke Energy Common Stock Fund are restricted to 20%.

Military Leave

Under the RSP, military leave of absence pay is not included in eligible pay. Upon your return to Duke Energy employment following a military leave, you can make military make-up 401(k) contributions up to the amount you could have made if you did not go on the military leave and receive the corresponding company matching contribution. To make it easier for you to get the most from the RSP's matching contributions, the RSP has a default rule related to military leave make-up contributions. If you make before-tax and/or Roth contributions higher than the amount needed to receive the regular company matching contribution during any plan year, your additional contributions will be treated as military make-up contributions to the extent eligible for prior year company matching contributions, as long as the additional contributions are made within the required time limit. Any eligible company matching contributions on make-up contributions will be calculated and made annually. You must be still employed by Duke Energy in order to receive military make-up contributions.

RSP investment funds

The RSP offers a variety of investment funds as well as Fidelity BrokerageLink®, a self-directed brokerage account. For current investment fund information, including historical performance information, please read the enclosed 2017 Investment Funds Summaries booklet.

The investment options available through the RSP are institutional funds, not mutual funds. Institutional funds are investment vehicles generally available only to certain types of investors, such as corporate pension plans with a 401(k) plan structure. Participation in these funds is usually subject to minimum asset sizes, but typically has the key benefit of lower fees and lower net operating costs versus those offered by retail mutual funds available to the individual investor.

Financial Engines

RSP investment help will be available through Financial Engines, an independent investment advice and management service provider. Please read page 46 of the enclosed 2017 Investment Funds Summaries booklet for more information about the services available through Financial Engines.

Fidelity Services

How do I start using Fidelity NetBenefits®? If you have never used Fidelity NetBenefits or have not established a Fidelity NetBenefits username and password through a previous employer's plan at Fidelity, you must establish a Fidelity NetBenefits username and password. Establishing your Fidelity NetBenefits username and password is simple. After RSP transactions become available during the week ending Jan. 6, 2018, log on to Fidelity NetBenefits at **401k.com** and follow the prompts to *Register* to create your username and password or call Fidelity's Duke Energy Customer Service Line at **800.376.4015**.

By using Fidelity NetBenefits or calling Fidelity's Duke Energy Customer Service Line, you can: enroll to make payroll contributions; change the amount or type (before-tax, Roth, after-tax) of your payroll contributions; change your investment elections; request exchanges (transfers) between investments (subject to the blackout period); review your RSP account information and chart your retirement savings; model a loan, verify your loan balance or initiate a loan; and determine the amount available for a withdrawal and initiate a withdrawal or distribution.

Participant Fees

In general, there are three types of fees that may be charged to your RSP account balance, all of which are subject to change.

- Plan administrative fees include a recordkeeping fee and trustee fees. You will pay a recordkeeping fee of $9.00 per quarter, deducted from your RSP account.

- Asset-based fees reflect a fund's total annual operating expenses and include management operating expenses and other fees. These are often the largest component of retirement plan costs and are paid by all shareholders of a fund. The investments in your account will be reduced by asset-based fees. Typically, asset-based fees are expressed as a percentage of the average net assets invested in the fund and are often referred to as an "expense ratio." A fund's expense ratio may change over time due to investment manager changes and/or changes in the amount of assets held in the fund.

- Individual fees will be charged to your account only if you complete certain transactions. For example, there is a loan setup fee associated with a new loan.

Please refer to page 8 of the enclosed 2017 Investment Funds Summaries booklet for details about the RSP's fees.

Actions to consider

Review your investment mix

Check the way your investments will transfer from the Piedmont 401(k) Plan and/or Piedmont MPPP to the RSP to make sure they will continue to meet your investment objectives. After the blackout period ends, review your investment mix in light of the available investment funds under the RSP. For details about the funds, read the enclosed 2017 Investment Funds Summaries booklet.

- To request changes in your Piedmont 401(k) Plan and/or Piedmont MPPP account prior to the blackout period, call Wells Fargo at **800.SAVE123**.

- To request changes to your RSP account after the blackout period, contact Fidelity's Duke Energy Customer Service at **800.376.4015**.

Review your savings strategy

Check the way your contribution elections under the Piedmont 401(k) Plan will transfer to the RSP and make any needed adjustments.

- To request changes to your Piedmont 401(k) Plan contribution elections prior to the blackout period, call Wells Fargo at **800.SAVE123**.

- To request changes to your RSP contribution elections after RSP transactions become available during the week ending Jan. 6, 2018, contact Fidelity's Duke Energy Customer Service Line at **800.376.4015**.

Check your beneficiary designations

Your beneficiary elections under the Piedmont 401(k) Plan and Piedmont MPPP will <u>not</u> transfer to the RSP.

- To view your beneficiaries under the Piedmont 401(k) Plan and Piedmont MPPP prior to the blackout period, call Wells Fargo at **800.SAVE123**.

- To designate beneficiaries under the RSP after RSP transactions become available during the week ending Jan. 6, 2018, contact Fidelity's Duke Energy Customer Service Line at **800.376.4015**.

Important notice

Duke Energy retains the right to amend, modify or terminate any benefit plan at any time, for any reason. Participation in a benefit plan is not a promise or guarantee of future employment. If any statement in this guide, or in any other communication, conflicts with the applicable Piedmont 401(k) Plan, Piedmont MPPP and/or RSP plan documents, the plan documents govern. This Notice provides general investment education, and nothing herein shall be construed as an investment recommendation or investment advice.

The Piedmont 401(k) Plan and RSP are intended to constitute plans described in Section 404(c) of the Employee Retirement Income Securities Act of 1974, as amended ("ERISA"), and Title 29 of the Code of Federal Regulations Sections 2550.404c-1, so that fiduciaries of the Piedmont 401(k) Plan and the RSP may be relieved of liability for any losses that are the direct and necessary result of investment directions given by the Piedmont 401(k) Plan and RSP participants or beneficiaries. The investment mapping is intended to be either an investment to the RSP's qualified default investment alternative or a qualified change in investment options under ERISA 404(c), so that your prior investment instructions continue to be considered an exercise of investment direction after the blackout period.

Where to go for more help

Get answers to your questions by calling Fidelity's Duke Energy Customer Service Line at **800.376.4015**. Representatives are available from 8:30 a.m. to 8:30 p.m. ET on business days, except NYSE holidays.

Find easy-to-use planning tools by logging on to **401k.com** and clicking on the "Menu" button and selecting either the "Tools" or "Library" icon.

- Try the Contribution Calculator to see how much more you could accumulate in your RSP account by increasing the amount that you contribute from each paycheck.
- Explore the Full View® to see how you can securely view all your financial accounts in one place.

Before investing in any fund, please carefully consider the investment objectives, risks, charges and expenses. For this and other information, call or write Fidelity for a free prospectus or, if available, a summary prospectus. Read it carefully before you invest.

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2017 November

Duke Energy Retirement Savings Plan
Summary Plan Description

Distribution Date: [Nov. 1, 2017]

Effective Date: Jan. 1, 2018 (except as otherwise provided)

INTRODUCTION

This booklet is the Summary Plan Description (“SPD”) for the Duke Energy Retirement Savings Plan (“RSP” or “Plan”) as in effect as of Jan. 1, 2018. The SPD reflects the following changes that are effective after the distribution date of this SPD:

- The merger of the Piedmont Natural Gas Company, Inc. 401(k) Plan (“Piedmont 401(k) Plan”) and Piedmont Natural Gas Company, Inc. Money Purchase Pension Plan (the “Piedmont MPPP”) into the RSP as of the close of Dec. 31, 2017.
- Prior to Jan. 1, 2018, employees on the payroll of Piedmont Natural Gas Company, Inc. and its affiliates (collectively, “Piedmont”) immediately prior to the Oct. 3, 2016 acquisition of Piedmont by Duke Energy Corporation ("Duke Energy") and its affiliates (the “Piedmont Acquisition”) and employees who are classified as employees of and paid on the Piedmont payroll after the Piedmont Acquisition generally were not eligible to participate in the RSP.
- Prior to Jan. 1, 2018, the RSP did not provide for employer transition credit contributions for eligible employees of Piedmont.
- Prior to Jan. 1, 2018, the RSP did not provide for employer retirement contributions to any employees covered by the collective bargaining agreement with IBEW System Council U-8.

Although the SPD describes the principal features of the RSP that are of general applicability, it is only a summary. Further, if your employment terminated prior to Jan. 1, 2018, some of the provisions of this SPD may not apply to you. The complete provisions of the RSP are set forth in the Plan documents, which are available upon request from the Duke Energy Benefits Committee (the "Benefits Committee"). An SPD is an overview and is written to be read in its entirety; descriptions of plan features should not be taken out of context. Changes to the RSP, pending revision of the SPD, will be communicated in Summaries of Material Modifications provided through newsletters, benefit statements, notices and/or enrollment materials. In the event of a conflict between an SPD or any other communication regarding the RSP and the Plan documents, the Plan documents will govern. Finally, the RSP may be amended only by proper corporate action and not by oral or written communications about the RSP. This SPD has been prepared by Duke Energy Corporation, and not Fidelity Investments ("Fidelity").

Neither the RSP, the SPD nor your Plan participation is an employment contract, nor do they give any employee the right to continue to be employed by Duke Energy.

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HIGHLIGHTS OF THE PLAN

The RSP was developed so that you and Duke Energy can work together to provide savings for your retirement. The following highlights of the RSP are general in nature and do not apply to all participants in all cases.

Participation In Plan	• As an employee of a participating company, you are immediately eligible to make contributions to the RSP. Certain Duke Energy employees are excluded. • An account will be established in your name after you enroll or are automatically enrolled to make contributions to the RSP or if you are eligible to receive employer retirement contributions or employer transition credit contributions.
Your Contributions	• You may contribute up to 75% of your eligible pay on a before-tax, Roth, and/or after-tax basis, but the total you contribute cannot be more than 75% of your eligible pay, subject to Internal Revenue Service ("IRS") limits. • If you will be age 50 or over at any time in the current calendar year, your before-tax and/or Roth limit will include the "catch-up" contribution limit. • For IRS limits, see page 4.
Matching Contributions	• Each pay period, the company will match before-tax, and/or Roth dollars you save based on your formula and eligible pay for company matching contributions. • Unless you are a Midwest union employee who earns pay and service in the Traditional Program under a company pension plan, each pay period, the company will match 100% of before-tax and/or Roth dollars you save up to 6% of your eligible pay for company matching contributions, subject to IRS limits. • Matching contributions will never be more than the lesser of your eligible pay multiplied by your applicable formula for matching contributions or the Internal Revenue Code (the "Code") section 402(g) limit. • For formulas and eligible pay for company matching contributions, see page 5 and 6, respectively.
Employer Retirement Contributions	• If you are not an active participant in a company pension plan, the company will make employer retirement contributions to your RSP account for each pay period equal to 4% of your eligible pay, subject to IRS limits. • Enrollment is not required in order to receive employer retirement contributions; however, you can select the investment funds into which employer retirement contributions are invested. • For information on eligibility and eligible pay for the employer retirement contribution, see page 5 and 6, respectively.
Employer Transition Credit Contributions	• If you were an active participant in the Retirement Plan of Piedmont Natural Gas Company, Inc. ("Piedmont Retirement Plan") on Dec. 31, 2017, the company will make employer transition credit contributions to your RSP account for each pay period for the 3-year period ending Dec. 31, 2020, subject to continued employment and IRS limits. If you are accruing disability benefits or in your disability waiting period on Dec. 31, 2017, you will accrue disability benefits under the Piedmont Retirement Plan formula (and not receive employer transition credit contributions). • Enrollment is not required in order to receive employer transition credit contributions; however, you can select the investment funds into which employer transition credit contributions are invested. • For information on eligibility and amount of the employer transition credit contributions, see page 5 and 6, respectively.

Vesting	• You are 100% vested in your RSP account at all times, except that a vesting schedule applies to employer retirement contributions (including attributable earnings) and amounts attributable to the Piedmont MPPP.
RSP Investment Funds and Fidelity BrokerageLink®	• The RSP currently offers access to a variety of different fund options as well as Fidelity BrokerageLink, a self-directed brokerage account. Information about the RSP's investment funds and Fidelity BrokerageLink can be found in the current RSP Investment Funds Summaries booklet on Fidelity NetBenefits at www.401k.com.
Retirement Resources	• Financial Engines, an independent investment advice and management service provider, also is available to provide investment help through Online Advice and its Professional Management program. • Financial Engines' Online Advice tool is available to you at no cost. If you wish to actively manage your own RSP account, you can get Online Advice to help you build your investing strategy, plan for income and model Social Security. To access Online Advice, log on to your RSP account at www.401k.com and click on the link "Get Personalized Help from Financial Engines." • For a fee, if you want ongoing help from independent investment experts, you can enroll in Financial Engines' Professional Management program to get ongoing management and monitoring of your RSP account investments. Additionally, Professional Management with Income+, which provides help with income planning through retirement, is available to RSP participants at least age 55 and within seven years of their planned retirement date. Duke Energy has negotiated an annual fee for this service equal to 0.50% of your managed account balance, and you can cancel your participation at any time without penalty. • Fidelity NetBenefits has retirement planning tools, including Full View®. Full View allows you to securely view your investment, retirement, bank, loan, mortgage and credit card accounts in one place. To access Full View, log on to your RSP account at www.401k.com and click on the link "Full View" located on the "Tools" tab on the home page.
Where to Find Information – Service is Just a Click Away	• You can access Fidelity NetBenefits at www.401k.com. Through Fidelity NetBenefits you can: o Enroll to begin saving through the Plan o Designate your beneficiary o Change deferral and investment elections o Request exchanges (transfers) between investments o Review your RSP account information and chart your retirement savings o Model and/or initiate a loan and verify your loan balance o Determine the amount available for a withdrawal and initiate a withdrawal or distribution • You also may call Fidelity's Duke Energy Customer Service Line at 1-800-376-4015. Representatives are available Monday through Friday (excluding New York Stock Exchange holidays), 8:30 a.m. – 8:30 p.m. Eastern Standard Time.

PARTICIPATION IN THE PLAN

General Eligibility

Generally, unless excluded as outlined below, you will be eligible to participate in the RSP if you are all of the following:

- An employee of a Duke Energy participating company.
- Paid on Duke Energy's U.S. payroll system.

A complete list of participating companies and collective bargaining units for the RSP may be obtained by participants and beneficiaries upon written request to the Benefits Committee. Participants and beneficiaries may receive from the Benefits Committee, upon written request, information as to whether a particular employer is a participating company in the RSP and, if a participating company, the participating company's address. A participating company ceases to be a participating company when it is no longer, directly or indirectly, at least 80% owned by Duke Energy, or when its designation as a participating company is discontinued by Duke Energy.

You are not eligible for the RSP if:

- You are covered under a collective bargaining agreement and there is no provision in effect that expressly provides for participation in the RSP.
- You are a non-resident alien with no U.S. source of income, or you are not on Duke Energy's U.S. payroll system.
- You have waived eligibility for the RSP through any means, including a written agreement that governs your employment (including an offer letter setting forth terms and conditions of employment) or a general statement in the agreement, offer letter, or other written communication that states you are not eligible for benefits or the RSP.

Making Contribution and Investment Elections

When you become eligible to participate in the RSP, you can make your contribution and investment elections immediately by logging on to Fidelity NetBenefits at www.401k.com or calling Fidelity's Duke Energy Customer Service Line at 1-800-376-4015. If you have never used Fidelity NetBenefits or have not established a Fidelity username and password through a previous employer's plan at Fidelity, you must establish a Fidelity NetBenefits username and password by logging on to Fidelity NetBenefits and following the prompts to "Register" to create your username and password.

If you are an eligible new employee and do not enroll to make contributions, you will be automatically enrolled to make contributions to the RSP soon after becoming eligible to participate in accordance with automatic enrollment information provided to you. Your initial contribution will be a 6% before-tax contribution to a default investment fund (*e.g.,* the Target Retirement Date Fund closest to the year you will reach age 65). If you want to increase your before-tax (or make Roth and/or after-tax) contributions, invest in a different fund, or decrease or stop your contributions, simply access Fidelity NetBenefits or call Fidelity.

Note that, if you are eligible for employer retirement contributions or employer transition credit contributions, you will receive those contributions in the Plan automatically, subject to IRS limits. You, however, will want to make investment elections for the employer retirement contributions or employer transition credit contributions. If you do not make an investment election, your employer retirement contributions or employer transition credit contributions will be invested in a default investment fund (*e.g.*, the Target Retirement Date Fund closest to the year you will reach age 65).

Rollover Contributions

If you have an account in another qualified retirement plan or an Individual Retirement Account ("IRA"), you may be allowed in certain circumstances to transfer or "roll over" contributions from that account to the RSP. Fidelity may request information from you in order to determine whether the RSP will accept the rollover contribution. Before-tax, Roth and after-tax accounts may be directly rolled over to the RSP from another employer's plan. Roth IRAs and after-tax IRAs, on the other hand, may not be rolled over to the RSP. In addition, if you terminate or retire from Duke Energy and elect a lump-sum payment (or other qualifying distribution) from a Duke Energy pension plan, you can roll over that money to your RSP account as long as you have an account balance under the RSP. Contact Fidelity to request instructions for performing a rollover to the RSP.

YOUR CONTRIBUTIONS

- You may elect to save up to 75% of your eligible pay, in whole or half percentages on a before-tax, Roth, and/or after-tax basis, but the total you contribute cannot be more than 75% of your eligible pay, subject to IRS limits which may change annually. The amount you elect to save will be automatically withheld from your pay. If you will be age 50 or over at any time in the current calendar year, your before-tax and/or Roth limit will include the "catch-up" contribution limit.
- No separate election is needed to make "catch-up" contributions. Existing IRS limits on contributions, including "catch-up" contributions, are shown in the chart below, which compares certain features of before-tax, Roth and after-tax contributions. Note that after-tax contributions will not be matched.
- Your contributions to the RSP are voluntary. If you decide to contribute (or are contributing pursuant to the automatic enrollment provisions), you may change the percentage of eligible pay that you are contributing or stop contributing at any time. Subject to IRS limits, you also can increase your RSP contributions automatically by up to 2% every year, using the RSP's automatic increase feature. When you elect to increase your RSP contributions using the automatic increase feature, you select the anniversary date on which your auto-increases occur. Auto-increases stop after your contributions reach 10%. You can opt out of the automatic increase feature

at any time. Any change will be effective as soon as administratively practicable.

- You are 100% vested in your contributions to the RSP (and earnings on your contributions).

The following chart compares certain features of before-tax, Roth and after-tax contributions.

	Before-tax	Roth	After-tax
Federal Taxation of Contributions	No	Yes	Yes
Investment Earnings Taxed While in Plan	No	No	No
Federal Taxation of Distributions (if no permissible rollover is made)	Yes – contributions and earnings are taxed and may be subject to a 10% early distribution penalty tax	No - if qualified distribution* If not a qualified distribution – portion attributable to earnings is taxed and may be subject to a 10% early distribution penalty tax*	In part – portion attributable to earnings is taxed and may be subject to a 10% early distribution penalty tax
Counted Toward Annual IRS Code Section 402(g) Limit (for 2017, $18,000 or, $24,000 including "catch-up" contribution limit)**	Yes	Yes	No
Counted Toward IRS Annual Code Section 415(c)(1)(A) Limit (for 2017, $54,000 or, $60,000 including "catch-up" contribution limit)***	Yes	Yes	Yes
Withdrawal Restrictions	Yes – available upon hardship, disability, or attainment of age 59-1/2	Yes – available upon hardship, disability, or attainment of age 59-1/2	No – available at anytime
Eligible for Company Match****	Yes – Matching formula applies to combined before-tax, and/or Roth contributions.	Yes – Matching formula applies to combined before-tax, and/or Roth contributions.	No

*A qualified distribution is a distribution made after the fifth anniversary of the first day of the first tax year of your first Roth contribution to the RSP and one of the following: on or after your attainment of age 59-1/2, in the event of disability, or to a beneficiary after your death.

** If the amount you contribute to the RSP, together with your contributions to any other tax-qualified plan, exceeds the IRS annual limit in any calendar year, you must notify the Fidelity retirement service center in writing by March 1 of the following year to receive a corrective distribution.

*** Company matching contributions and any employer retirement contributions or employer transition credit contributions also count toward the IRS annual code section 415(c)(1)(A) limit.

**** Company matching contributions and earnings are taxed upon distribution regardless of whether the match was made with respect to before-tax or Roth contributions.

Certain higher-paid participants may be affected by IRS rules that "cap" the amount of employee and/or company contributions that can be made to the RSP. If these rules affect you in a particular year, you may be required to limit the amount of your contributions, and/or your excess contributions (along with earnings) will be returned to you. You will be notified if you are affected by these limits.

Your before-tax and Roth contributions (as well as wages attributable to after-tax contributions) are always included in wages for Social Security taxes. Although state and local income tax laws vary, they usually follow the federal rules. You may wish to consult a tax advisor to determine how your before-tax and Roth contributions will be taxed under your local laws.

Whether before-tax, Roth contributions and/or after-tax contributions are right for you depends on your personal circumstances. In general, you will want to maximize company matching contributions through making before-tax and/or Roth contributions. You should consult with your personal tax advisor regarding which type of contribution is best for you.

COMPANY CONTRIBUTIONS

- To add to your savings in the RSP, the company currently makes matching contributions to the RSP. See the Company Contributions Summary Chart below for the matching formula applicable to you.
- The following chart summarizes the company contributions that are made to the RSP:

COMPANY CONTRIBUTIONS SUMMARY CHART

	Company Matching Formula*			Employer Retirement Contribution*	Employer Transition Credit Contributions
Percentage of Eligible Pay	100% of before-tax and/or Roth contributions up to 6% of eligible pay	100% on before-tax and/or Roth contributions up to 3% of eligible pay and 50% on before-tax and/or Roth contributions on the next 2% of eligible pay**	100% on before-tax and/or Roth contributions up to 4% of eligible pay and 50% on before-tax and/or Roth contributions on the next 1% of eligible pay	4% of eligible pay with no contribution required	3%, 4%, or 5% of eligible pay based on years of vesting service as of Dec. 31, 2017
Applies to	Non-union and, unless described in the next two columns to the right, union employees represented by IBEW Locals 962, 962T; 1347, 1393, 1902, and System Council U-8; USW Locals 5541-06, 7202 and 12049; UWUA Local 600, and PPF 702.	Union employees represented by IBEW Local 1393, USW Locals 5541-06 and 12049; and UWUA Local 600, who participate in the Traditional Program under a company pension plan	Union employees represented by IBEW Local 1347, who participate in the Traditional Program under a company pension plan	Non-union and union employees covered by the RSP who do not participate in a company pension plan	Legacy Piedmont non-union and IBEW Local 1902 and PPF 702 represented employees who were active participants in the Piedmont Retirement Plan on Dec. 31, 2017. Contributions cease after Dec. 30, 2020.
Vesting Requirement of Contributions (Including Attributable Earnings)	No	No	No	100% upon completion of 3 years of service or, while employed, you attain age 65, die or become disabled.*** Amounts attributable to cash dividends on Duke Energy common stock are fully vested.**** The above 3-year vesting schedule also applies to amounts attributable to the Piedmont MPPP.****	No

*Company contributions (*i.e.*, matching, employer retirement and employer transition credit contributions) are invested in accordance with your current investment elections.

**Employees also are eligible for a company-made incentive matching contribution of up to 1% of eligible pay based on the

achievement of corporate goals and your making employee before-tax and Roth contributions with respect to 5% of your eligible pay for the year. That is, the incentive matching contribution will not be more than 1% of eligible pay and is based on a specified percentage (determined pursuant to corporate goals) of employee before-tax and Roth contributions made with respect to your eligible pay of up to 5% for the year.

***Your years of service for purposes of vesting generally includes your completed years and months of service from your hire date until your severance from service date. If you have a severance from service and return to work within 12 months of your severance from service date, you will receive service for your period of severance and your prior service will be restored. If you have a severance from service and return to work 12 or more months after your severance from service date, you will not receive any service for your period of severance. However, your prior service will be restored if you were vested in your RSP account on your severance from service date or you were reemployed after a period of severance of less than 60 months. The non-vested portion of any employer retirement contributions will be forfeited if you receive or are deemed to receive a distribution of the vested portion of your RSP account or if you have a period of severance of at least 60 months. If employer retirement contributions are forfeited and you are reemployed, the forfeiture will be restored only if your reemployment occurs prior to a period of severance of less than 60 months.

****For purposes of vesting in these contributions, vesting service of Piedmont employees will equal the sum of (a) vesting service under the Piedmont MPPP as of Dec. 31, 2017, (b) vesting service determined under the RSP's elapsed time method for periods on and after Jan. 1, 2018, and (c) an additional 9 months of vesting service.

- The RSP includes a make whole matching feature for participants employed on the last day of the plan year (Dec. 31) who did not contribute at an even rate throughout the plan year (and did not receive a full matching contribution as a result). The make whole matching contribution is subject to the applicable IRS and RSP limits for the plan year for which the make whole matching contribution relates.
- If you do not participate in a company pension plan (*i.e.*, in general, you were hired or rehired after the date specified in the chart below), the company provides an employer retirement contribution to the RSP equal to 4% of your eligible pay each pay period.

Employee Group	Hire or Rehire Date after
Legacy Piedmont non-union employees and IBEW Local 1902 represented employees	Dec. 31, 2007
PPF Local 702 represented employees	Dec. 31, 2008
Non-union employees (other than legacy Piedmont non-union employees) and USW Local 7202 represented employees	Dec. 31, 2013
IBEW Local 1347 represented employees	Dec. 31, 2014
IBEW Locals 962 and 962T represented employees	March 31, 2015
IBEW Local 1393 and UWUA Local 600 represented employees	Dec. 31, 2015
USW Locals 5541-06 and 12049 represented employees	Dec. 31, 2016
IBEW Systems Council U-8 represented employees	Dec. 31, 2017

- If you were an active participant in the Piedmont Retirement Plan on Dec. 31, 2017, the company provides employer transition credit contributions to the RSP equal to the applicable percentage of your eligible pay set forth in the chart below, based on your years of vesting service as of Dec. 31, 2017, for each pay period during the 3-year period ending Dec. 31, 2020.

Vesting Service as of Dec. 31, 2017	Percentage of Eligible Pay
less than 15 years	3%
at least 15 years, but less than 25 years	4%
25 or more years	5%

ELIGIBLE PAY

Eligible pay for purposes of employee contributions, matching contributions, employer retirement contributions and employer transition credit contributions is shown in the chart below.

Employee Classification	Employee Contributions	Matching Contributions	Employer Retirement Contributions	Employer Transition Credit Contributions
Non-union and union employees (other than IBEW System Council U-8) represented employees who do <u>not</u>	• Base pay • Overtime • Unused vacation pay (when paid after	Same as for Employee Contributions	Same as for Employee Contributions, except that before-tax contributions to the	Not applicable

participate in a company pension plan	termination) • Most short-term incentive pay • Lump sum merit pay • See below*		Duke Energy Executive Savings Plan are included	
IBEW System Council U-8 represented employees who do <u>not</u> participate in a company pension plan	• Hourly base rate of pay (*e.g.,* multiplied by 80 hours for a two-week pay period) • See below**	Same as for Employee Contributions	Same as for Employee Contributions	Not applicable
Non-union and union employees who participate in a company sponsored pension plan other than (i) IBEW 1347, IBEW 1393, USW 5541-06 and 12049; or UWUA Local 600 represented employees who participate in the Traditional Program, (ii) IBEW System Council U-8 represented employees, or (iii) Piedmont employees	• Base pay • Overtime • Unused vacation pay (when paid after termination) • Most short-term incentive pay • Lump sum merit pay • See below*	Same as for Employee Contributions	Not applicable	Not applicable
IBEW 1347 represented employees who participate in the Traditional Program under a company pension plan	• Base pay • Overtime • Unused vacation pay (when paid after termination) • Most short-term incentive pay • Lump sum merit pay • See below*	• Base pay • Unused vacation pay (when paid after termination) • See below***	Not applicable	Not applicable
IBEW 1393, USW 5541-06 and 12049; and UWUA Local 600 represented employees who participate in the Traditional Program under a company pension plan	• Base pay • Overtime • Unused vacation pay (when paid after termination) • See below**	• Base pay • Unused vacation pay (when paid after termination) • See below***	Not applicable	Not applicable
IBEW System Council U-8 represented employees who participate in a company pension plan	• Hourly base rate of pay (*e.g.,* multiplied by 80 hours for a two-week pay period) • See below**	Same as for Employee Contributions	Not applicable	Not applicable
Legacy Piedmont non-union and IBEW Local 1902 and PPF 702 represented employees who were active	• Base pay • Overtime • Unused vacation pay (when paid after	Same as for Employee Contributions	Not applicable	Same as for Employee Contributions, except that before-tax contributions to the Duke Energy Executive Savings Plan

participants in the Piedmont Retirement Plan on Dec. 31, 2017 and participate in a company sponsored pension plan	termination) • Most short-term incentive pay • Lump sum merit pay • See below*			are included

The amount you elect to save will be automatically withheld from your pay up to your elected contribution percentage, provided that your pay is sufficient after applicable taxes and other deductions are withheld. If your pay is not sufficient after applicable taxes and other deductions are withheld, partial deductions will be taken from your elected contribution percentage and may leave you with no pay.

Your eligible pay is subject to IRS compensation limits (for 2017, your eligible pay is limited to the first $270,000 paid to you).

* Amounts that you elect to defer are included if made from otherwise eligible pay, including amounts you elect to defer under the RSP on a before-tax basis, contributions you pay on a before-tax basis for coverage under the medical, vision and dental plan, amounts that you contribute to the health and dependent care spending accounts and health savings accounts, and amounts you pay for commuter benefits.

The following compensation items are not included: reimbursements and allowances for expenses; cash or non-cash fringe benefits; severance pay; moving expenses; non-qualified deferred compensation; cash in lieu of long-term incentive pay; bonuses for performance periods in excess of one year; long-term incentive payments (incentives attributable to multi-year performance period) and compensation in the form of, or otherwise based upon, the value of Duke Energy common stock; transition pay; military leave pay (including military differential wage payments); or any other compensation item that has been determined not to be eligible by the company. Compensation also does not include any amounts paid following termination of employment, except for the following if paid within 60 days following termination of employment – unused vacation, sick pay, short-term incentive pay or certain eligible compensation that would have been paid regardless of your employment termination.

** For part-time employees, actual basic compensation is used, including any lump sum pay increases to basic compensation and amounts that you elect to defer under the RSP on a before-tax basis, contributions you pay on a before-tax basis for coverage under the medical, vision and dental plan, amounts that you contribute to the health and dependent care spending accounts and health savings accounts, and amounts you pay for commuter benefits, in each case if made from otherwise eligible pay.

***Amounts that you elect to defer under the RSP on a before-tax basis, contributions you pay on a before-tax basis for coverage under the medical, vision and dental plan, amounts that you contribute to the health and dependent care spending accounts and health savings accounts, and amounts you pay for commuter benefits also are included if made from otherwise eligible pay. No other forms of compensation are included.

INVESTING THROUGH THE RSP

The RSP offers a variety of investment fund options as well as Fidelity BrokerageLink. When you enroll to make contributions, you will be required to choose how you want your future contributions under the RSP to be invested. If you are enrolled to make contributions through automatic enrollment, your future contributions will be invested in a default investment fund (*i.e.*, the Target Retirement Date Fund closest to the year you will reach 65) until you choose how you want your future contributions to be invested. If you are eligible to receive employer retirement contributions or employer transition credit contributions, those contributions will be invested in the same manner as your contributions (*i.e.*, pursuant to your investment election or, if you have not made an investment election, in the default investment fund). You may transfer existing balances in the default investment fund to other RSP investment funds.

You are responsible for directing the investments in your RSP account. You have the right to direct your RSP account balance as well as any future contributions among the RSP investment options. For current investment fund information, restrictions on transferring amounts to or between RSP investment funds, Fidelity BrokerageLink requirements, and fees associated with the RSP, please read the current *RSP Investment Funds Summaries* booklet. You should review the *RSP Investment Funds Summaries* booklet very carefully and consult your investment advisor when considering investment fund decisions for your RSP account. The *RSP Investment Funds Summaries* booklet can be obtained via Fidelity NetBenefits at www.401k.com or by calling Fidelity's Duke Energy Customer Service Line at 1-800-376-4015.

Statement of Your RSP Account

After the end of each calendar quarter, you will receive a statement that will detail your RSP account's activity for the quarter. You may elect to receive an electronic or paper copy of your statement by logging on to Fidelity NetBenefits at www.401k.com and updating "Your Profile" by clicking on the link "Mail Preferences" or by calling Fidelity's Duke Energy Customer Service Line at 1-800-376-4015. You may change

your statement delivery election at any time. Online RSP account information as well as Plan information and documents are available every day.

Company Stock – Voting and Dividend Election

If a portion of your RSP account is invested in the Duke Energy Common Stock Fund, you have the right to direct Fidelity Management Trust Company, the Trustee, on how to vote your RSP account's proportionate interest in Duke Energy common stock held by the Duke Energy Common Stock Fund as of the record date for the vote. See the Investment Funds Summaries booklet for more information.

Generally, Duke Energy pays quarterly cash dividends on its common stock, including shares held by the Duke Energy Common Stock Fund. You may elect to receive a cash payout of your RSP account's allocation of the current dividend or to have that allocation reinvested in the fund (with the option to transfer to one of the other investment funds available under the RSP). The dividend payout/reinvestment election may be made at any time during the year, effective with the next dividend payment, with the exception of elections made during the 10-business-day period prior to the ex-dividend date. The ex-dividend date is generally 30 days prior to the dividend payment date. If you have never made an election, the dividend allocation will remain in the RSP. Your RSP account's allocation of the current dividend is based on your account's investment in the fund at the time of the dividend.

Dividends paid to you in cash are taxable as a plan distribution (not as investment income) for the calendar year in which they are paid (even if paid from amounts attributable to Roth contributions). Dividends paid to you in cash are not subject to the 10% federal tax penalty for early distributions and are not eligible for a rollover to an IRA or similar plan. Dividends reinvested in the Duke Energy Common Stock Fund are subject to the same tax rules as other earnings under the RSP (*e.g.*, taxation generally is deferred until distribution and amounts distributed generally are eligible for rollover to an IRA or similar plan). Note that there currently is a $6 charge to issue a dividend check and a $3 charge to electronically transfer a dividend payout to your bank account.

Notice of Your Rights Concerning Employer Securities and RSP's Stock Restriction

This notice informs you of an important federal law that provides specific rights concerning investments in employer securities (company stock). Because you may now or in the future have investments in company stock through the Duke Energy Common Stock Fund under the RSP, you should take the time to read this notice carefully.

Your Rights Concerning Employer Securities
The RSP must allow you to elect to move any portion of your RSP account that is invested in company stock from that investment into other investment alternatives under the RSP. This right extends to all of the company stock held under the RSP. You may contact Fidelity's Duke Energy Customer Service Line at 1-800-376-4015 for specific information regarding this right, including how to make this election. In deciding whether to exercise this right, you will want to give careful consideration to the information below that describes the importance of diversification. All of the investment options under the RSP are available to you if you decide to diversify out of company stock.

The Importance of Diversifying Your Retirement Savings
To help achieve long-term retirement security, you should give careful consideration to the benefits of a well-balanced and diversified investment portfolio. Spreading your assets among different types of investments can help you achieve a favorable rate of return, while minimizing your overall risk of losing money. This is because market or other economic conditions that cause one category of assets, or one particular security, to perform very well often cause another asset category, or another particular security to perform poorly. If you invest more than 20% of your retirement savings in any one company or industry, your savings may not be properly diversified. Although diversification is not a guarantee against loss, it is an effective strategy to help you manage investment risk.

In deciding how to invest your retirement savings, you should take into account all of your assets, including any retirement savings outside of the RSP. No single approach is right for everyone because, among other factors, individuals have different financial goals, different time horizons for meeting their goals, and different tolerances for risk. Therefore, you should carefully consider the rights described in this notice and how these rights affect the amount of money that you invest in company stock through the RSP.

It also is important to periodically review your investment portfolio, your investment objectives, and the investment options under the RSP to help ensure that your retirement savings will meet your retirement goals.

For More Information
If you have any questions about your rights under this law, including how to make this election, contact Fidelity's Duke Energy Customer Service Line at 1-800-376-4015 or the Benefits Committee.

RSP's Employer Stock Restriction
To promote investment diversification, the following restrictions apply to the Duke Energy Common Stock Fund:

- Investment elections for future contributions into the Duke Energy Common Stock Fund (including rollover contributions and loan repayments) will be limited to 20 percent of the contribution.
- No exchanges (transfers) into the Duke Energy Common Stock Fund will be allowed if your investment in the Duke Energy Common Stock Fund is 20 percent or more of your RSP account balance, or if the exchange would result in your investment in the Duke Energy Common Stock Fund exceeding 20 percent of your RSP account balance. (There are no restrictions on your ability to exchange out of the Duke Energy Common Stock Fund.)
- If you elect to rebalance your entire RSP account in a single transaction, any allocation to the company stock fund will be restricted to no more than 20 percent of your RSP account balance.

LOANS

If you are actively employed by Duke Energy or any of its affiliated companies, you may borrow money from your RSP account balance. Amounts attributable to employer retirement contributions, employer transition credit contributions and Piedmont MPPP (collectively, the "Retirement Contributions") are not available to fund loans and are excluded from determining the maximum loan limit of 50% of your account balance.

Loan Limits

The minimum you may borrow is $1,000. The maximum you may borrow is the lesser of:

- $50,000, less your highest outstanding loan balance during the 12 months prior to the loan request, or
- 50% of your total vested account balance other than any amounts attributable to the Retirement Contributions. The Benefits Committee (or its delegate) specifies the maximum number of outstanding loans that are allowed from the RSP are two. Defaulted loans are considered outstanding loans and will count against the limit and will be considered when calculating the maximum available loan amount.

Source of Loan

Loans will be taken from sources (*e.g.*, before-tax) within your RSP account other than any amounts attributable to Retirement Contributions, in the sequence prescribed by the Benefits Committee (or its delegate). Within each of the available sources, money taken for the loan will be prorated across the various RSP investment funds in which these amounts are invested.

Rate of Interest

The interest rate on your loan is based on the prime lending rate plus 1% and will remain in effect for the term of the loan. The prime lending rate is based on the daily prime rate feed provided by Reuters at the close of business on the last business day of the month prior to the month in which your loan is made.

Loan Collateral

Generally, fifty percent (50%) of the value of your RSP account other than any amounts attributable to the Retirement Contributions, at the time of a loan will be collateral for the outstanding balance of the loan made to you.

Repaying Your Loan

The term of all loans, other than loans used to acquire your principal residence, is for a period of up to 58 months. Loans used to acquire a principal residence may be repaid over a term of up to 15 years. Repayments are to be made at regular intervals, as determined by the Benefits Committee (or its delegate).

Loan repayments, including interest, are made through after-tax payroll deductions except that, if payroll deductions to the Plan are not available at your payroll location, loan repayments are made in accordance with procedures prescribed by the Benefits Committee (or its delegate). The repayments will be paid back into various funds, according to your current investment election for your contributions. You may choose to prepay all or part of the unpaid balance of your loan in a lump sum payment at any time, without penalty. A prepayment can be made by certified check, money order or electronic funds transfer. If you have two outstanding loans and repay one of the loans, there is a 15-day waiting period from the time the loan is repaid until a new loan can be taken.

If you miss regular loan repayments for any reason, other than generally an approved unpaid leave of absence, the missed payments must be made up by the end of the following calendar quarter from which the loan repayments were missed. If the missed payments are not made, the unpaid principal and accrued interest will be deemed (or actually) distributed with corresponding income tax consequences.

If you have an outstanding loan balance at the time your employment terminates for any reason, other than by reason of death, you may continue to make loan payments over the loan's terms in accordance with procedures prescribed by the Benefits Committee (or its delegate).

WHEN YOU CAN RECEIVE YOUR RSP ACCOUNT

In-Service Withdrawals

Certain amounts may be withdrawn from the RSP while you are still employed by Duke Energy or any of its affiliated companies. The RSP provides for several different types of in-service withdrawals. You may make one withdrawal of each type per month. You cannot roll over these withdrawals back into the RSP. Amounts attributable to employer retirement contributions, employer transition credit contributions and Piedmont MPPP (employer contributions) are not available for in-service withdrawals.

Withdrawals will be withdrawn from investment funds on a prorated basis across the various RSP investment funds in which your RSP account is invested, unless you call Fidelity's Duke Energy Customer Service Line at 1-800-376-4015 and specify the investment funds from which you want the withdrawal to be taken.

Any-Time In-Service Withdrawals

You may, while employed, withdraw amounts associated with the following contributions at any time:

- Rollover contributions

- After-tax contributions
- ESOP contributions (amounts transferred from the Duke Energy Corporation Employees' Stock Ownership Plan, the TRASOP associated with the Employees Savings Plan of PanEnergy Corporation and Participating Affiliates, the Tax Credit Employee Stock Ownership Plan of PanEnergy Corp and Participating Affiliates, and Piedmont Natural Gas Company, Inc. Employee Stock Ownership Plan)
- Duke Energy company matching contributions made prior to Jan. 1, 2008 (*i.e.*, company matching contributions for persons who participated in the Duke Energy RSP prior to 2008)
- Progress Energy company matching contributions made prior to Jan. 1, 2010 (*i.e.*, the matured company account as transferred from the Progress Energy 401(k) Savings & Stock Ownership Plan (the "Progress Energy Plan"))

Age 59-1/2 Withdrawals

Generally, if you have attained age 59-1/2, you may, while employed, withdraw all vested amounts in your RSP account other than Retirement Contributions.

Disability Withdrawals

If you become totally disabled under a long term disability plan of Duke Energy or any of its affiliated companies, you may, while active, withdraw all amounts in your RSP account.

For amounts attributable to the Piedmont MPPP, amounts are distributable after you have been totally and permanently disabled for 12 months. For the Piedmont MPPP, total and permanent disability means a physical or mental condition arising after the date on which you complete an hour of service and totally and permanently prevents you from engaging in any occupation or employment for remuneration or profit, except for purpose of rehabilitation not incompatible with a finding of total and permanent disability, but does not include a disability (i) arising from or consisting of habitual drunkenness or addiction to narcotics, (ii) contracted, suffered or incurred while you were engaged in or resulted from your engaging in a criminal enterprise, (iii) that was intentionally self-inflicted, (iv) arose out of service in the armed forces of any country, (v) arose while you were on a leave of absence, or (vi) that resulted from your being engaged in some other occupation or business for profit.

For amounts attributable to the Piedmont 401(k) Plan, amounts are distributable after you are totally and permanently disabled. For the Piedmont 401(k) Plan, total and permanent disability means a physical or mental condition that totally and permanently prevents you from engaging in any occupation or employment for Duke Energy or any of its affiliated companies as evidenced by eligibility for benefits under the Social Security Act or determined as such by a licensed physician (as approved by the Plan Administrator).

Uniformed Services Withdrawals

The following contributions transferred from the Progress Energy Plan are available for withdrawal if you have been performing services in the uniformed services for at least 31 days: Progress Energy Plan participant deferrals, participant catch-up deferrals and company safe harbor matching contributions. If you take an in-service withdrawal in accordance with this provision, you will not be eligible to make contributions to the RSP for the six month period beginning on the date of the withdrawal.

Progress Energy Plan participant deferrals and participant catch-up deferrals transferred from the Progress Energy Plan are available for withdrawal if you are a member of a reserve component ordered or called to active duty for a period in excess of 179 days or for an indefinite period.

Hardship Withdrawals

You may, while employed, withdraw all amounts in your RSP account on account of financial hardship, except for any amounts attributable to Retirement Contributions, any safe harbor matching contributions, and earnings earned after 1988 with respect to your before-tax and/or Roth contributions. A financial hardship is limited to the need to pay for:

- The purchase of your principal residence (excluding mortgage payments).
- Tuition, related educational fees and room and board expenses for the next 12 months of post-secondary education for you, your spouse or your dependents.
- Expenses for medical care for you, your spouse or dependents that are not reimbursable through group health care coverage or insurance, but that would be deductible under tax rules without regard to income limits.
- The prevention of foreclosure on, or eviction from, your principal residence.
- Burial or funeral expenses for your deceased parent, spouse, child or dependent.
- Expenses to repair damages to your principal residence that would qualify for a casualty deduction under tax rules.

The withdrawal cannot be for more than the amount needed to pay for the actual expenses causing the financial hardship (plus any amounts necessary, up to an additional 25%, in order to pay applicable taxes).

In order to receive a hardship withdrawal, you must:

- Satisfy the RSP's requirements explained above.
- Be unable to satisfy the hardship from other sources, and you must have obtained all loans and withdrawals available from the RSP.

If you take a hardship withdrawal, your before-tax, Roth, and after-tax contributions to the RSP will be suspended for 6 months.

Benefits After Death

If you die before receiving your full RSP account balance, the vested balance of your RSP account other than the amount attributable to the Piedmont MPPP will be payable to your beneficiary in a lump sum payment as soon as practicable after your death, unless your beneficiary chooses to defer payment for up to five years from the date of your death. The death benefit attributable to the Piedmont MPPP may be distributed (i) for a non-spouse beneficiary, in the form of a complete distribution in a lump sum or payments over a period certain of monthly, quarterly or annual installments of up to 5 years, so long as payment in full is made within 5 years of the participant's death and (ii) for a spouse beneficiary, in the form of a complete distribution in a lump sum or payments over a period certain of monthly installments of up to 5 years or a complete distribution through the purchase of a single life annuity for the spouse's life, so long as payment in full is made by date you would have attained age 70½.

If you are married at the date of your death, your spouse will be your beneficiary unless you have elected another beneficiary on the prescribed form with your spouse's written consent, notarized by a notary public. Only RSP beneficiary designations made through Fidelity (or if transferred electronically as part of a plan merger) are valid. If a beneficiary designation is not made through Fidelity, RSP default provisions will apply (*i.e.*, your spouse will be your beneficiary and, if you have no spouse, then your estate will be your beneficiary).

If you have a Piedmont MPPP account under the RSP, the following special rule will apply to your entire account under the RSP. If you designate a non-spouse beneficiary under the RSP while employed before the year in which you attain age 35, the designation expires on the first day of the year in which you attain age 35. You can again designate the same or another beneficiary (with spousal consent, as applicable) on or after the first day of the year in which you attain age 35 (or at any time after you are no longer employed).

Special Distribution Rules

You must begin receiving distributions in the minimum amount required by law from your RSP account under the RSP no later than the later of:

- April 1 following the year in which you reach age 70-1/2, or
- The date your employment with Duke Energy terminates.

HOW YOUR RSP ACCOUNT IS PAID

Distributions

Following termination of employment from Duke Energy and its affiliated companies, you are entitled to receive the vested balance in your RSP account. If your vested balance is $1,000 or less, you will automatically receive a complete distribution of the vested balance in your RSP account. If your vested balance is greater than $1,000, may choose to receive a partial or complete distribution, monthly, quarterly or annual installments over a specified period (subject to IRS rules) or defer distribution or leave your account in the RSP until a later date, subject to provisions below for the portion of your account attributable to the Piedmont MPPP. A partial distribution can be implemented manually (*i.e.*, one partial distribution at a time) or automatically, through a Systematic Withdrawal Plan ("SWP"). There are three types of SWPs available: Flat Dollar Amount, meaning you chose to receive a fixed-dollar amount; Decrementing Counter, meaning the SWP is determined by multiplying your account balance by a counter that reduces each time a SWP is paid (*e.g.*, 1/10, 1/9, 1/8); and a Minimum Required Distribution (MRD), meaning the minimum required amount will be paid on either a monthly, quarterly or annual basis.

For the portion of your account attributable to the Piedmont MPPP, you may also elect complete distribution through the purchase of (i) if you are not married, a single life annuity for your life (ii) if you are married, a 100% or 50% joint and survivor annuity that provides monthly payments for your life and, after your death, monthly payments for your spouse's life equal to 100% (normal form) or, if you elect, 50%. If you are married, payment of the portion of your account attributable to the Piedmont MPPP is required in the normal form unless you obtain your spouse's written consent that is witnessed by a notary public to payment in another form (*e.g.*, lump sum).

Option to Receive Distribution in Duke Energy Common Stock

When you request a distribution, it generally will be paid to you in cash. You may, however, elect to receive the entire amount that is invested in the Duke Energy Common Stock Fund as of the date of distribution in whole shares of Duke Energy common stock, and cash for any fractional shares. Also, distribution in the form of a purchase of an annuity (as described above) is available for the portion of your account attributable to the Piedmont MPPP.

Taxes on Payments

If you are going to receive or rollover money from the RSP, you should review the IRS "Special Tax Notice Your Rollover Options" and discuss tax implications of the payment with your personal tax advisor. This is particularly appropriate if you are receiving money before age 59-1/2.

Rollovers

All or a part of a distribution that qualifies as an eligible rollover distribution can be rolled over within 60 days to another employer's eligible plan (if that plan accepts rollovers), a 403(b) contract, an eligible plan maintained by certain government employers, an IRA or Roth IRA. A distribution from Roth savings (including any earnings) can be rolled over only to another designated Roth account or to a Roth IRA. By using

a rollover, you generally can avoid paying current income tax on the distribution and, if it applies, the 10% tax penalty on early distributions. Note that, the amount of a direct rollover from non-Roth savings to a Roth IRA (reduced by any after tax amounts) will be taxed. In the event of your death, your spouse and, in limited circumstances with a direct rollover, your beneficiary also can use a rollover to avoid paying current income tax on an eligible rollover distribution. Eligible rollovers do not include:

- Loan proceeds when taking out a loan from the RSP.
- A hardship withdrawal.
- Any part of a payment that is part of a required minimum payment that must be paid to you after you reach age 70-1/2.
- ESOP dividends taken in cash.
- Payments to non-spouse alternate payees under a Qualified Domestic Relations Order.
- A distribution that is a series of substantially equal periodic payments for a specified period of 10 or more years or for your life or the joint lives of you and your designated beneficiary.

In a direct rollover, the distribution or withdrawal check or stock certificate will be in the name of the trustee or the custodian of the eligible plan and will be sent to you for your delivery to the trustee or custodian. In-kind rollovers may be permitted in certain circumstances.

IRS Publications 575 and 590 provide additional information about the tax treatment of plan distributions and rollovers. These publications are available from your local IRS office, on the IRS's website at www.irs.gov, or by calling 1-800-TAX-FORMS.

OTHER IMPORTANT INFORMATION

Claims and Appeal Procedures

If you have a claim for benefits or any grievance, complaint or claim concerning any aspect of the administration of the RSP, or the RSP's trust, including the administration of any investment fund, you must submit your written claim to the Retirement Benefits Department, c/o Duke Energy Corporation, 550 South Tryon (DEC 38D), Charlotte, NC 28202-1803 or in accordance with such other procedures as the Benefits Committee or its delegate prescribes. You must submit each claim no later than two years from the earliest of:

- in the case of any account balance or other account transaction information, the date such information was first made available to you,
- in the case of any payment or series of payments, the date of payment or the date the first in the series of payments was paid, or
- for all other claims, the date on which the action complained of first occurred.

Your claim must be in writing and include:

- a statement that it is a claim under the Duke Energy Retirement Savings Plan;
- your full name, mailing address and daytime telephone number;
- if applicable, a copy of your written designation of a representative, including the representative's full name, mailing address and daytime phone number; and
- a complete description of the claim, including any issue or information you or your representative want considered.

If your claim is denied, either in whole or in part, you or your representative will receive written notification within 90 days after receipt of your claim, unless special circumstances require an extension of time for processing the claim. If an extension is necessary, you will be notified, in writing, and the extension period will not be for more than 90 days. At any point in the claims process, you or your representative may request documents relevant to your claim from the Claims Committee, which documents will be provided free of charge.

If your claim is denied, a written notice of decision will contain (a) a statement of the specific reasons for the adverse determination, (b) a reference to the specific RSP provision(s) on which the decision is based, (c) a description of any additional material or information necessary for you to perfect your claim and an explanation of why the material or information is necessary, and (d) a description of the RSP's review procedures and the time limits applicable to the procedures, including a statement of your right to bring a civil action under Section 502(a) of the Employee Retirement Income Security Act of 1974, as amended, ("ERISA") following an adverse benefit determination on review.

If your claim is denied, you may file a written appeal with the Claims Committee c/o Duke Energy Corporation, 550 South Tryon Street (DEC38D), Charlotte, NC 28202 within 60 days after the claim for benefits was denied. The Claims Committee will then review the denied claim and give written notice of its final decision. Your appeal must be in writing and include:

- a statement that it is an appeal under the Duke Energy Retirement Savings Plan;
- your full name, mailing address and daytime telephone number;
- if applicable and not previously submitted, a copy of your written designation of a representative, including the representative's full name, mailing address and daytime telephone number; and
- a complete description of the appeal including a description of the original claim and any issue or information that you or your representative want considered.

The review will take into account all comments, documents, records and other information submitted by you, without regard to whether the information was submitted or considered in the initial benefit determination.

The final decision notice will be furnished within 60 days, or, if special circumstances require more time, within 120 days. The Claims Committee must promptly inform you, in writing, of the reason for the delay and the date you can expect to receive a notice. The notification of the Claims Committee's benefit determination review, if adverse to you, will contain (a) the specific reasons for the adverse determination, (b) a reference to the specific RSP provision(s) on which the decision is based, (c) a statement that you are entitled to receive, upon request to the Claims Committee and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to your claim for benefits, and (d) a statement of your right to bring a civil action under Section 502(a) of ERISA following an adverse benefit determination review. You may, at any time during the claim denial or review process, hire an attorney – at your own expense – to represent you. You must first follow the RSP's claims procedures prior to filing any action or lawsuit, and any action or lawsuit must be filed no later than one year from the date of the decision on appeal. The RSP's proper name and your name should be used in any related formal correspondence.

The Plan Administrator may institute such additional procedures as appropriate.

Special Rules for Disability Determinations

With respect to a determination of total and permanent disability for amounts attributable to the Piedmont 401(k) Plan and Piedmont MPPP (other than determinations based on legibility for Social Security benefits), a claim decision will be provided within 45 days of receipt of the claim. If an extension is necessary, you will be notified and the extension will not be more than 30 days, but a second extension may be taken for an additional 30 days. Any extension notice will specify the circumstances requiring the extension and the date a decision can be expected. The extension notice also will explain the standards for approving a disability claim; state the unresolved issue(s) that prevent a decision from being reached, and describe any additional information needed to resolve the issue(s).

If your claim is denied, the following additional information will be provided: (i) If the claim denial is based on a medical necessity or experimental treatment or similar exclusion or limit, that an explanation of the scientific or clinical judgment for the determination, applying the terms of the Plan to your medical circumstances, is available upon request, free of charge. (ii) A statement that you are entitled to receive, upon request and free of charge, reasonable accesses to, and copies of, all documents, records and other information relevant to your claim. (iii) A discussion of the determination, including an explanation of the basis for disagreeing with or not following: (a) the views presented by you of health care professionals treating you and vocational professionals who evaluated you, (b) the views of medical or vocational experts whose advice was obtained on behalf of the Plan in connection with your determination, without regard to whether the advice was relied upon in making the determination, and (c) a disability determination regarding you made by the Social Security Administration.* (iv) Either the specific internal rules, guidelines, protocols, standards or other similar criteria of the Plan relied upon in making the determination or a statement that such rules, guidelines, protocols, standards or other similar criteria of the Plan do not exist.* (v) A statement displayed in any applicable non-English language clearly indicating how to access the language services provided by the Plan.*

You may request a review of the claim decision within 180 days, rather than 60 days. The review will not afford deference to the original claim denial and will be conducted by a Plan fiduciary different from the fiduciary who originally denied your claim. This fiduciary also cannot be subordinate to the fiduciary who originally denied your claim.

If the original denial of your claim was based on a medical judgment, the reviewing fiduciary will consult with an appropriate health care professional who has appropriate training and experience in the field of medicine involved in the medical judgment and who is neither a health care professional consulted on the original claim nor subordinate to such consulted health care professional. The review will identify the medical or vocational experts consulted on the original claim, without regard to whether the advice was relied upon in making the benefit determination. You may request, in writing, a list of those medical or vocational experts.

Before an adverse determination on review is issued, you will be provided, free of charge, with the following as soon as possible and sufficiently in advance of the date on which notice of the determination is required to give you a reasonable opportunity to respond prior to that date: (i) Any new or additional evidence considered, relied upon, or generated by (or at the direction of) the Plan, insurer, or other person making the determination in connection with the Claimant’s claim. (ii) If the determination is based on a new or additional rationale, the rationale.

You will receive notice of the reviewing fiduciary's final decision regarding your disability claim within 45 days, rather than 60 days, of the review request. If your claim or review is denied, the notice will state the following additional information:(i) If the claim denial on review is based on an exclusion or limit (such as a medical necessity requirement or an experimental treatment exclusion), that an explanation of the scientific or clinical judgment applying the exclusion or limit to your medical circumstances is available upon request, free of charge. (ii) A statement that you and the Plan may have other voluntary alternative dispute resolution options, such as mediation and that one way to find out what may be available is to contact the local U.S. Department of Labor Office and State insurance regulatory agency. (iii) A discussion of the determination, including an explanation of the basis for disagreeing with or not following: (a) the views presented by you of health care professionals treating you and vocational professionals who evaluate you, (b) the views of medical or vocational experts whose advice was obtained on behalf of the Plan in connection with the determination, without regard to whether the advice was relied upon in making the determination, and (c) a disability determination regarding you made by the Social Security Administration.* (iv) Either the specific internal

rules, guidelines, protocols, standards or other similar criteria of the Plan relied upon in making the determination or a statement that such rules, guidelines, protocols, standards or other similar criteria of the Plan do not exist.* (v) A statement displayed in any applicable non-English language clearly indicating how to access the language services provided by the Plan.* (vi) Any applicable contractual limitations period that applies to your right to bring an action under Section 502(a) of ERISA, including the calendar date on which the contractual limitations expires for the claim.*

*The Department of Labor has proposed delaying and/or eliminating these new requirements. The information will only be provided if required by applicable Department of Labor regulations.

Assignment of Rights

Your RSP account and other rights under the RSP may not be assigned, transferred or pledged to a third party and, generally, may not be involuntarily taken, such as by your creditors. The RSP will, however, in circumstances required by law, comply with a Qualified Domestic Relations Order that directs a portion of your RSP account balance to be paid to a former spouse or other dependent. The RSP also will offset your RSP account (i) to the extent that you received any overpayments from the RSP, (ii) to satisfy IRS federal tax liens, and (iii) in accordance with certain judgments regarding malfeasance with respect to the RSP.

Amendment or Termination of the RSP

While Duke Energy expects the RSP to continue, it reserves the right to amend, discontinue, or terminate the RSP at any time. Upon termination of the RSP, participants' accounts will be fully vested and distributed as permitted by law.

Benefits Are Not Guaranteed

Account balances (including your contributions and Retirement Contributions under the RSP are not insured by the Pension Benefit Guaranty Corporation ("PBGC"). Generally, the PBGC insures certain benefits under defined benefit plans in the event of a plan termination. The RSP, as a defined contribution plan, is not eligible for PBGC insurance. Your RSP benefit depends on a number of variable factors, such as how much you save and investment results. If the RSP investment funds in which your RSP account is invested experience losses, the value of your RSP account will decrease.

General Federal Tax Considerations of the RSP

The RSP is intended to qualify under Code section 401(a). Assuming the RSP meets the requirements of the Code, the following general income tax consequences will result:

- Duke Energy generally will be entitled to a deduction for amounts it contributes to the RSP.
- The RSP's trust will not be subject to federal income tax.

While on a Leave of Absence for Military Service

Under the Uniformed Services Employment and Reemployment Rights Act ("USERRA"), you are entitled to a military leave of absence, with reinstatement rights. If you are a participant in the RSP and you are placed on a military leave of absence, your contributions (before-tax, Roth, and/or after-tax), company matching contributions, employer retirement contributions, employer transition credit contributions and loan payments will not continue. If your return to employment following a military leave is timely, you will receive any employer retirement contributions and employer transition credit contributions that you would have received had you not gone on military leave. You also can make military make-up contributions (before-tax, Roth and/or after-tax contributions) up to the amount you could have made if you did not go on the military leave and receive the corresponding company matching contribution that you could have received.

For these contributions, any IRS and RSP limits will apply to the year to which the contribution relates, not the year in which the contribution is made. Your contributions, any employer retirement contributions, employer transition credit contributions and company matching contributions generally will be determined using deemed compensation for the period of uniformed service. The RSP includes the following default rule to make it easier to maximize your company matching contributions: If you make before-tax and/or Roth contributions in excess of the amount necessary to receive the regular company matching contribution for a plan year, the excess before-tax and Roth contributions will be treated as military make-up contributions to the extent eligible for prior year company matching contributions.

Once you return to active work, any suspended loan payments will resume immediately.

If you die while performing qualified military service, survivor benefits will include any additional benefits that would have been provided under the RSP had you returned to employment (immediately prior to your death) and then terminated employment on account of death.

Qualified Domestic Relations Order

Federal law permits payment of all or a portion of your RSP account to an alternate payee, provided that such a payment is made pursuant to a court order (in some cases a governmental agency), relating to child support, alimony, or marital property rights payments, that is a Qualified Domestic Relations Order or "QDRO." The RSP will determine the qualified status of any domestic relations order received. If you have questions about a Qualified Domestic Relations Order or to obtain, without charge, a copy of the RSP's procedures governing QDRO determinations (including model domestic relations orders), please contact the myHR Service Center at 1-888-465-1300 or access the QO Center website link located on Fidelity NetBenefits at www.401k.com.

Important Restrictions and Consequences

You may receive less than you expect from the RSP in the following situations:

- Your benefit is the value of your RSP account balance and you assume the risk of investment losses. Under section 404(c) of ERISA, Plan fiduciaries may be relieved of liability for any losses that are the direct and necessary result of the investment decisions you make.
- Your employment is terminated before you are vested in your entire benefit.
- Highly compensated employees may be required to reduce their contributions to satisfy IRS discrimination tests.
- All employees are subject to IRS benefit and contribution limits.
- All or part of your benefit is assigned to an alternate payee pursuant to a qualified domestic relations order (QDRO).
- You fail to keep the Benefits Committee (or its delegate) notified of your current address.
- The RSP may be amended or terminated at any time.
- Benefits may be eliminated or suspended as permitted by law.
- All or part of your benefit is offset to recoup overpayments made to you.
- If you are married, the normal form of payment for the amounts attributable to the Piedmont MPPP is a purchased qualified joint and surviving spouse annuity. You may elect a lump sum only with your spouse's consent (witnessed by a notary).
- Benefits under the RSP are paid only if the Benefits Committee (or its delegate, including the Claims Committee) decides in its discretion that the applicant is entitled to benefits under the RSP.

Fees

In making decisions regarding the RSP, you will want to consider the fees and expenses that will be charged to your RSP account. In general, fees can be classified into the following categories:

Plan Administrative Fees. Your RSP account is charged fees for general plan administration expenses (*e.g.*, recordkeeping services).

Plan Transaction Fees. Your RSP account will be charged fees for certain RSP transactions, including the following: (a) a loan set up fee for each loan transaction, (b) a per quarter, per loan, maintenance fee for loans received, (c) a fee for each in-service withdrawal, (d) a fee for each minimum required distribution, (e) a fee for each dividend payment distribution by check (a fee for each dividend payment distribution by electronic fund transfer (direct deposit)), (f) a fee for the return of excess deferrals resulting from your participation in multiple plans and (g) if applicable, a Financial Engines Professional Management fee. No separate fee is charged for establishing a Fidelity BrokerageLink account, but standard brokerage commission fees will be charged for transactions in the Fidelity BrokerageLink account.

Investment Fund Fees. Currently, there are no RSP-level transaction fees or expenses which affect your RSP account in connection with investing in or transferring from one RSP investment fund to another. Your RSP account, however, will be reduced by a number of expenses or fees associated with your investment choices, including fees charged by some or all of the following entities: the Trustee, investment advisors, investment managers, and securities brokers.

For additional information on RSP investment fund fees, refer to the current *RSP Investment Funds Summaries* booklet.

PLAN INFORMATION

Name and Type of Plan

The name of the plan is the Duke Energy Retirement Savings Plan and is commonly referred to as the Retirement Savings Plan or RSP. The RSP and this summary are subject to ERISA. The RSP is a defined contribution plan under ERISA, is an "ERISA 404(c) plan" because of your investment control over your RSP account, is intended to be a qualified plan under the Code, includes a cash or deferred arrangement under Code section 401(k), and includes the Duke Energy Common Stock Fund, which is an employee stock ownership plan.

Employer and Plan Identification Number

The employer identification number assigned by the IRS is: 20-2777218.

The Plan number assigned by Duke Energy is: 002 for the Duke Energy Retirement Savings Plan.

Plan Administrator and Sponsor As Well As Stock Issuer

The Duke Energy Benefits Committee is the plan administrator and is responsible for the administration of the Plan. You may obtain additional information about the RSP or contact the Benefits Committee at:

Benefits Committee
c/o Duke Energy Corporation
550 South Tryon Street (DEC38D)
Charlotte, NC 28202
704-382-4703

The Investment Committee generally determines the RSP investment funds available for participant selection under the RSP, retains investment managers, selects collective investment funds, issues investment guidelines and objectives, and monitors RSP investment fund performance (except for the Duke Energy Common Stock Fund, which is monitored by the Duke Energy Company Stock Investment Review

Committee). The Investment Committee and the Duke Energy Company Stock Investment Review Committee may be contacted at:

Investment Committee
Director, Long Term Investments
c/o Duke Energy Corporation
550 South Tryon Street (DEC40A)
Charlotte, NC 28202
704-382-4703

RSP Trustee and Funding

The RSP is funded through both employee and Duke Energy and other participating companies' contributions to the RSP's trust. The Trustee holds the assets of the RSP in a Master Trust.

The Trustee of the RSP's trust is:
Fidelity Management Trust Company
82 Devonshire Street
Boston, MA 02109

Agent for the Service of Legal Process

The agent for service of legal process upon the RSP is:

Corporate Secretary
c/o Duke Energy Corporation
550 South Tryon Street (DEC45A)
Charlotte, NC 28202

Legal process also may be served on the RSP Trustee or the Benefits Committee.

Plan Year

The Plan Year begins on Jan. 1 and ends on the following Dec. 31.

YOUR ERISA RIGHTS

As a participant in the RSP, you are entitled to certain rights and protections under ERISA. ERISA provides that all Plan participants shall be entitled to:

Receive Information About Your Plan Benefits

- Examine, without charge, at the plan administrator's office, all documents governing the Plan, including insurance contracts and collective bargaining agreements, and a copy of the latest annual report (Form 5500 Series) filed by the Plan with the U.S. Department of Labor and available at the Public Disclosure Room of the Employee Benefits Security Administration.

- Obtain, upon written request to the Benefits Committee, copies of documents governing the operation of the Plan, including insurance contracts and collective bargaining agreements, and copies of the latest annual report (Form 5500 Series) and updated summary plan description. The administrator may make a reasonable charge for the copies.

- Receive a summary of the Plan's annual financial report. The Benefits Committee is required by law to furnish each participant with a copy of this summary annual report.

- Obtain a benefit statement from the Plan, at no charge to you, at least once every twelve (12) months.

Prudent Actions by Plan Fiduciaries

In addition to creating rights for plan participants, ERISA imposes duties upon the people who are responsible for the operation of the employee benefit plan. The people who operate your Plan, called "fiduciaries" of the Plan, have a duty to do so prudently and in the interest of you and other Plan participants and other beneficiaries. No one, including your employer, your union, or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a Plan benefit or exercising your rights under ERISA.

Enforce Your Rights

- If your claim for a Plan benefit is denied or ignored, in whole or in part, you have a right to know why this was done, to obtain copies of documents relating to the decision without charge, and to appeal any denial, all within certain time schedules.
- Under ERISA, there are steps you can take to enforce the above rights. For instance, if you request a copy of Plan documents or the latest annual report from the Plan and do not receive them within 30 days, you may file suit in a federal court. In such a case, the court may

require the Benefits Committee to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Benefits Committee. If you have a claim for benefits which is denied or ignored, in whole or in part, you may file suit in a state or federal court. In addition, if you disagree with the Plan's decision or lack thereof concerning the qualified status of a domestic relations order or a medical child support order, you may file suit in federal court. If it should happen that Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and fees. If you lose, the court may order you to pay these costs and fees, for example, if it finds your claim is frivolous.

Assistance With Your Questions

If you have any questions about this Plan, you should contact Fidelity's Duke Energy Customer Service Line at 1-800-376-4015 or the Benefits Committee. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Benefits Committee, you should contact the nearest office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue N.W., Washington, D.C. 20210. You also may obtain certain publications about your rights and responsibilities under ERISA by calling the publications hotline of the Employee Benefits Security Administration.

401(k) transition

The Piedmont Natural Gas Company Inc. 401(k) Plan will merge into the Duke Energy Retirement Savings Plan (RSP) and you will participate in the RSP on and after Jan. 1, 2018.

In November, you will receive information that describes how your current Piedmont 401(k) account will transition to the RSP, along with information about the RSP and the investment funds available in the RSP effective as of Jan. 1, 2018.

Piedmont 401(k)	Duke Energy 401(k)
Piedmont 401(k) Plan • Company match – 100% of before-tax contributions up to **5%** of eligible pay • 500 hours in a 6-month period required for vesting for company match • Before-tax contributions only • Investment funds include a mix of retail mutual funds, along with risk-based model portfolios comprised of retail mutual funds	**Duke Energy Retirement Savings Plan (RSP)** • Company match – 100% of before-tax and Roth contributions up to **6%** of eligible pay • Immediate vesting for company match • Before-tax, Roth and/or after-tax contributions • Investment funds include o Institutional funds (not retail funds) o Duke Energy Common Stock Fund o Opportunity to enroll in BrokerageLink, a self-directed brokerage account that provides access to individual securities (for example, stocks, bonds, mutual funds and more)
Wells Fargo is service provider	Fidelity Investments® is service provider

Pension transition

After Dec. 31, 2017, your accrued pension benefit under the Retirement Plan of Piedmont Natural Gas Company Inc. (Piedmont Pension Plan) will freeze and merge into the Duke Energy Retirement Cash Balance Plan (RCBP) and you will retain all benefits accrued through Dec. 31, 2017. As shown on the following table, effective Jan. 1, 2018, you will begin accruing another pension benefit under a cash balance formula. Additionally, Duke Energy also will make employer transition credit contributions to your RSP account during your continued employment based on your vesting service as of Dec. 31, 2017, as shown in the following table. These contributions will end the earlier of Dec. 31, 2020 or your termination date.

At retirement, your vested pension benefit will have at least two parts – a final average pay benefit and a cash balance benefit. Importantly, you will not lose the benefits that you've accrued as of Dec. 31, 2017.

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For Piedmont employees hired prior to Jan. 1, 2008

Piedmont Pension Plan	Duke Energy RCBP
• Final average pay (FAP) formula based on age, benefit service and eligible pay • Years of benefit service are capped at 35 • Reductions for commencement prior to normal retirement age	• Frozen FAP as of Dec. 31, 2017 **plus** • Cash balance formula beginning Jan. 1, 2018 under Duke Energy's RCBP • Monthly company contributions (pay credits) are based on points (age + years of service with Piedmont, Duke Energy and any predecessor companies thereof) ➤ < 35 points 4% of eligible pay ➤ 35 – 49 points 5% of eligible pay ➤ 50 – 64 points 6% of eligible pay ➤ 65 points or greater 7% of eligible pay • Contribution percentage is based on number of points at the beginning of each calendar year • Additional monthly pay credits of 4% of eligible pay in excess of Social Security wage base ($127,200 in 2017) • Monthly interest credits added to cash balance based on an annual 4% interest rate
Forms of payment • Lump sum • Single life annuity • Joint and survivor annuity • Life with guaranteed payments	**Forms of payment for cash balance** • Lump sum • Single life annuity • Joint and survivor annuity
	• No service cap in cash balance design • **Employer transition credit contributions** are additional company contributions to your RSP account that will be made each pay period ➤ Based on vesting service as of Dec. 31, 2017 • < 15 years 3% • 15 – 24 years 4% • 25 years or greater 5% ➤ Will only be made for 3-year period beginning Jan. 1, 2018 and ending Dec. 31, 2020

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401(k) transition

The Piedmont Natural Gas Company Inc. 401(k) Plan will merge into the Duke Energy Retirement Savings Plan (RSP) and you will participate in the RSP on and after Jan. 1, 2018.

In November, you will receive information that describes how your current Piedmont 401(k) account will transition to the RSP, along with information about the RSP and the investment funds available in the RSP effective as of Jan. 1, 2018.

Piedmont 401(k)	Duke Energy 401(k)
Piedmont 401(k) Plan • Company match – 100% of before-tax contributions up to **5%** of eligible pay • 500 hours in a 6-month period required for vesting for company match • Before-tax contributions only • Investment funds include a mix of retail mutual funds, along with risk-based model portfolios comprised of retail mutual funds	**Duke Energy Retirement Savings Plan (RSP)** • Company match – 100% of before-tax and Roth contributions up to **6%** of eligible pay • Immediate vesting for company match • Before-tax, Roth and/or after-tax contributions • Investment funds include o Institutional funds (not retail funds) o Duke Energy Common Stock Fund o Opportunity to enroll in BrokerageLink, a self-directed brokerage account that provides access to individual securities (for example, stocks, bonds, mutual funds and more)
Wells Fargo is service provider	Fidelity Investments® is service provider

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Money Purchase Pension Plan transition

After Dec. 31, 2017, your accrued benefit under the Piedmont Natural Gas Company Inc. Money Purchase Pension Plan (MPP Plan) will be frozen and merged into the RSP, and, in addition to matching contributions, Duke Energy will make employer retirement contributions to your RSP account equal to 4% of eligible pay each pay period, subject to IRS limits.

Piedmont	Duke Energy
MPP Plan • Company contribution of 4% of eligible pay annually in January for previous calendar year • Additional 4% contribution of eligible pay in excess of the Social Security wage base ($127,200 in 2017) • Must be employed on last day of year or retired during year to receive contribution	**RSP** • Employer retirement contributions of 4% of eligible pay each pay period • Refer to the previous section for information about the RSP
• 3-year vesting	• 3-year vesting (includes Piedmont service)
Wells Fargo is service provider	Fidelity Investments is service provider

In November, you will receive information that describes how your current Piedmont 401(k) account and MPP Plan account will transition to the RSP, including information about the RSP and the investment funds available in the RSP.

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ERISA 204(h) Notice for Participants of the
Piedmont Natural Gas Company, Inc. Money Purchase Pension Plan

The purpose of this communication is to advise you of future changes to the Piedmont Natural Gas Company, Inc. Money Purchase Pension Plan (the "Piedmont MPPP") effective Dec. 31, 2017.

Background: Freezing of Piedmont MPPP benefits

In accordance with an amendment to the Piedmont MPPP, no additional contributions will be made to the Piedmont MPPP after Dec. 31, 2017[1]. That is, future accruals under the Piedmont MPPP will be frozen after Dec. 31, 2017. You will not lose any of the benefits you have earned under the Piedmont MPPP up to Dec. 31, 2017. Effective at the close of Dec. 31, 2017, your Piedmont MPPP account will be merged into the Duke Energy Retirement Savings Plan (the "RSP"). You will continue to earn service for Duke Energy employment for purposes of vesting in amounts attributable to the Piedmont MPPP under the RSP. Beginning Jan. 1, 2018, you will be eligible to participate in the RSP employer retirement contribution formula, which is described in further detail below.

Piedmont MPPP benefit formula prior to freeze

Prior to the freezing of future accruals, the Piedmont MPPP provided for an annual company contribution equal to 4% of eligible pay, plus an additional 4% of eligible pay in excess of the Social Security Wage Base. This contribution was contributed once per year into the Piedmont MPPP account in January, and was based on compensation from the prior calendar year. The Social Security Wage Base is determined each year by the Social Security Administration. In 2017, the Social Security Wage Base was $127,200. An employee must be employed on the last day of a year or have retired or died during the year to receive a contribution.

New provisions: RSP

Beginning Jan. 1, 2018, you will participate in the RSP employer retirement contribution formula, which provides a contribution of 4% of eligible pay to your RSP account. These contributions are made each pay period. These contributions are in addition to employer matching contributions under the RSP.

This Notice complies with the disclosure requirements under Section 204(h) of the Employee Retirement Income Security Act of 1974 as amended (ERISA), and section 4980F of the Internal Revenue Code of 1986, as amended, regarding the cessation of benefit accruals under the Piedmont MPPP. This document contains selected highlights of Duke Energy's employee benefits plans. If any statement herein, or any other communication, conflicts with applicable plan documents, the plan documents will govern. Duke Energy retains the right to amend, modify or terminate its benefits plans in any respect and at any time, and neither its benefits plans nor your plan participation will be considered a contract for future employment.

[1] Note that the contribution you earned on account of employment during 2017 will be credited to your Duke Energy Retirement Savings Plan account in January 2018.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-119. Refer to MFR 11 Attachment.xlsx as provided with the Company's filing. Specifically, refer to tabs "TN Alloc Income Stmt – 2019" and "Tn Alloc IS March 2020." Provide ledger support for the charges making up account 090240 Director's Expenses in both tabs.

RESPONSE: See attachment.

Name and Title of Preparer: Paul Mosley, Rates and Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 2, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-120. Refer to MFR 11 Attachment.xlsx as provided with the Company's filing. Specifically, refer to tabs "TN Alloc Income Stmt – 2019" and "Tn Alloc IS March 2020." Provide responses to the following regarding Account "930250 – Buy/Sell Transf Employee Homes."

a) The title (and co.) of the employee served by these expenditures.

b) The purpose of the expenditure.

c) Why the Company believes these costs are recoverable from ratepayers.

d) Provide the Company's written corporate policy for how/when such costs can be reimbursed to an employee.

RESPONSE: See the Company's response to Request No. 123.

Name and Title of Preparer: Paul Mosley, Rates and Regulatory Strategy Analyst

Name and Title of Responsible Person: Quynh Bowman, Director - Gas Rates & Regulatory Strategy

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
Consumer Advocate's First Discovery Request
Date Issued: August 17, 2020
Date Due: September 8, 2020

1-121. Refer "5K_OtherAG Adj.xlsx" as provided with the Company's Filing. Specifically, refer to tab "Other A&G Detail." For all charges to account 921100 Employee Expenses with "Aviation Corporate Jets" or "Aviation Corporate Hanger" in column L "RC Long Descr CB"; provide the following information by trip:

a) A description of the business purpose for the travel.

b) How the travel relates to the provision of natural gas service.

c) The title(s) and company of the employee traveling.

d) Flight log of trip.

RESPONSE: The items that were selected in this data request total to $4,389.20 as allocated to Piedmont's Tennessee operations. They represent expenses charged to DEBS and allocated to Piedmont pursuant to the Cost Allocation Manual provided in the Company's response to item 57 of this data request. As seen in the CONFIDENTIAL attachment, there are over 800 transactions recorded on DEBS books which when allocated to Piedmont TN totals $4,389.20.

Piedmont would need to pull each transaction individually and analyze each item to adequately respond to this question. Given the time allowed to respond to this data request, Piedmont was unable to research over 800 transactions.

Piedmont did review the ten highest dollar transactions (ranging from $39.74 to $95.57) and noted the charges represent expense reports and accounts payable invoices related to

the administration of the corporate aviation function. The expenses selected are not necessarily related to a specific flight on corporate aircraft.

Piedmont suggests selecting a sample of these transactions for further analysis.

Name and Title of Preparer: Jeff Masucci, Senior Financial Analyst

Name and Title of Responsible Person: Jeff Setser, Director Allocations and Reporting

Response provided by Piedmont Natural Gas Company, Inc. on September 8, 2020.

PIEDMONT NATURAL GAS COMPANY, INC.
Docket No. 20-00086
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1-122. Refer "5K_OtherAG Adj.xlsx" as provided with the Company's Filing. Specifically, refer to tab "Other A&G Detail." For all charges to Accounts "921200 Office Expenses", "921600 Other", "92300 Outside Services Employed" with "Aviation Corporate Jets" or "Aviation Corporate Hanger" in column L "RC Long Descr CB"; provide a cost benefit analysis supporting the benefit of using a corporately owned aircraft over commercial airline for travel. This analysis should include all costs associated with ownership (including but not limited to insurance, pilot compensation, taxes, fuel, storage, return on the cost of the asset(s), etc.)

RESPONSE: The Company does not have a cost-benefit analysis regarding commercial flights versus use of corporate aircraft. Use of corporate aircraft is determined and reserved based on Duke Energy's Corporate Aviation policy. See attachment.

Name and Title of Preparer: Jeff Masucci, Sr. Financial Analyst

Name and Title of Responsible Person: Jeff Setser, Director - Allocations & Reporting

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Applicability:	Senior Management Committee
Originator:	Aviation Services
Approval:	Vice President Administrative Services
Effective Date:	July 1, 2019
Revision Date:	**June 19, 2019**
Revision No:	5
Reissue Date:	

Statement of Purpose and Philosophy

Corporate Aviation is designed to maximize executive productivity, safety and security in support of Duke Energy's strategy and core business. This Corporate Aviation policy ("Policy") describes the general processes, expectations and authority for use of Duke Energy aircraft. The Chairman, President & CEO, as well as Senior Management Committee members, the Senior Vice President/Chief Nuclear Officer and the Senior Vice President of Nuclear Operations (Authorizers) may request and approve the use of corporate aircraft in accordance with this Policy and should familiarize themselves with the guidance and expectations outlined herein. When questions or interpretations of this Policy are warranted, the Managing Director of Aviation or the Vice President Administrative Services should be contacted.

Corporate Aviation - General Use Expectations

Corporate Aviation, including owned, leased, chartered and fractional aircraft, is the preferred form of domestic and international air travel for the Chairman, President and CEO (CEO) . Aviation studies will be conducted periodically to gauge continued feasibility of this guidance and all compensation and tax issues related to this guidance will be reviewed and approved by the Compensation Committee of the Duke Energy Board of Directors (the Board).

Senior Management Committee (SMC) members should, but are not required to, use Corporate Aviation for their business travel. When not utilizing Corporate Aviation, First Class or Business Class travel is the preferred method for commercial travel.

Roles and Responsibilities

- **Policy Development & Reporting:** The Managing Director of Aviation Services and the Vice President Administrative Services are accountable for the development, oversight and communication of this Policy. Reports will be provided as needed and authorized by the Vice President Administrative Services through his/her management chain to the CEO and/or Governance Committee of the Board.

- **Safety & Compliance:** The Managing Director of Aviation Services is responsible for ensuring that Corporate Aviation provides technical reviews and safety assessments of business travel on Duke Energy aircraft as well as private, non-Duke Energy aircraft directed for executive use by Corporate Aviation.

- **Executive Spacing Protocol:** The Corporate Aviation team is responsible for following the Executive Spacing Protocol as approved by the Governance Committee of the Board.

Priority Use Guidelines

Priority use and scheduling will always be given to the CEO and Board of Directors. Secondary priority will be given to SMC members.

General Use Guidelines

- Due to the confidential nature of travel by the Authorizers, Corporate Aviation will not provide travel information to other executives, or their representatives, relating to travel by others. Corporate Aviation remains committed to optimizing the use of corporate aircraft whenever possible.

- The CEO has blanket dispatch approval authority for herself, the Board, employees and non-employees.

- Authorizers have dispatch approval authority for (i) themselves, for (ii) employees in their respective organizations and (iii) non-employees who are conducting business for the Enterprise.

- SMC members have dispatch approval authority for non-employees who are conducting business for their respective organizations that is not directly associated with Duke Energy, (i.e. economic development).

- When an Authorizer cancels his/her travel plans and employees or non-employees were scheduled to accompany the Authorizer, the trip must be reapproved unless the manifest contains another Authorizer.

- When the original requester (non-Authorizer) cancels his/her travel plans, the trip must be reapproved unless the manifest contains another employee who is at a management level equivalent to or higher than the original requester.

- The Authorizer shall not delegate dispatch approval authority.
-
- SMC members may utilize Corporate Aviation for purely personal travel. Appropriate legal documents (e.g. time share agreements) must be executed prior to purely personal trips. Ride along personal travel (e.g. spouse accompanying an Authorizer on business), should be an infrequent occurrence. All personal travel must be in accordance with the Personal Use of Corporate Aviation Procedure.

- Duke Energy aircraft will not be used to transport elected officials or their staffs.
-
- Duke Energy aircraft should not be used to transport non-profit organization staff or guests, absent advanced approval by the Vice President Administrative Services. The only pre-approved non-profit uses of the aircraft are the Corporate Angel Network and the Special Olympics Cessna Airlift. The Vice President Administrative Services may approve other non-profit support which is consistent with the mission of Duke Energy.

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1-123. Refer to MFR 11 Attachment.xlsx as provided with the Company's filing. Specifically, refer to tabs "TN Alloc Income Stmt – 2019" and "Tn Alloc IS March 2020." Provide responses to the following regarding Account "930250 – Buy/Sell Transf Employee Homes."

a. The title of the employee to whom the costs relate.

b. The employee's business unit.

c. Complete explanation of the purpose of the expenditure(s).

d. Why the Company believes these costs are recoverable from ratepayers.

e. Provide the Company's written corporate policy for how/when such costs can be reimbursed to an employee.

RESPONSE:

a. See CONFIDENTIAL attachment. As seen in Excel column Q on the second tab in the attachment, the total amount of relocation expense allocated to Tennessee operations during the test period is $10,736.08.

For transactions arising from accounts payable invoices from NEI Global Relocation Company, the employee title has been provided. This represents $3,632.71 (approx. 34%) of the total amount allocated to Tennessee. The remaining 103 transactions are largely journal entry transactions that would need to be analyzed individually to determine the job titles of the employees to whom the costs relate. Given the time allowed to respond to this data request, Piedmont was unable to complete this task. Piedmont suggests selecting a sample of the remaining transactions for further analysis.

b. All charges selected are related to employees of Business Unit 20013 Duke Energy Business Services (DEBS).

c. These charges represent some of the costs of various employee relocation expenses. The types of expenses can vary by employee and which relocation program they are under, but can include household goods and storage, home finding and rental finding assistance, temporary living assistance, and other expenses related to the relocation process.

d. These costs are normal and reasonable business expenses to attract and retain certain employees.

e. Duke Energy has various relocation programs to assist employees who are required to relocate for employment reasons. See CONFIDENTIAL attachments 1 through 5 for a description of the corporate relocation programs.

Name and Title of Preparer:

a. & b. Laura Hager, Lead Rates & Regulatory Strategy Analyst

c. Patti Doster, Lead Accounting Analyst

d. Quynh Bowman, Director - Gas Rates & Regulatory Strategy

e. Jennifer Edwards, Lead HR Consultant

Name and Title of Responsible Person:

a. & b. Quynh Bowman, Director - Gas Rates & Regulatory Strategy

c. David Dye, Accounting Manager II

d. Quynh Bowman, Director - Gas Rates & Regulatory Strategy

e. Jake Stewart, Manager – Compensation

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1-124. Refer to COS DR #15_TN Labor by O&M Acct 12mth ended 3-31-20 Rev 6-15-20 Updated MAC.xlsx. Specifically, refer to tab "TN O&M 4-2019-3-2020 All". Provide responses to the following regarding Resource Type Long Description "Directors' Saving Plan" charged to account 9200.

a. The title of the employee to whom the costs relate.

b. The employee's business unit.

c. The purpose of the expenditure

d. An explanation of how such costs are earned under the program

e. All materials provided to employees outlining the program

RESPONSE: The total amount recorded to Tennessee allocated operations during the test period 4/1/19 - 3/31/20 for Director's Savings Plan expense was a credit (reduction to expense) of $12,243.59.

a. The participants in the Director Savings Plan are not employees of Duke Energy, but rather, are members of the Board of Directors for the Company.

b. The costs associated with the plan participants is recorded on business unit 20013 - Duke Energy Business Services (DEBS).

c. The purpose of the expenditure is to record/adjust the liability to represent the obligation related to Directors' balances of deferred compensation.

d. Directors may elect to receive all or a portion of their annual cash compensation or eligible stock awards on a current basis or defer such compensation under the Directors' Savings Plan.

e. See CONFIDENTIAL attachment.

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Name and Title of Preparer: Jennifer Piasky, Senior Accounting Analyst

Name and Title of Responsible Person: David Dye, Mgr Accounting II

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